State of California
AIR RESOURCES BOARD

PUBLIC HEARING TO CONSIDER THE PROPOSED REGULATION FOR GREENHOUSE GAS EMISSION STANDARDS FOR CRUDE OIL AND NATURAL GAS FACILITIES

STAFF REPORT: INITIAL STATEMENT OF REASONS

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EXECUTIVE SUMMARY

Background

Climate change is one of the most serious environmental threats facing the world today, and California is already feeling the effects. California has committed to take action to address the threat. Under AB 32, the California Global Warming Solutions Act of 2006, ARB was identified as the state agency charged with monitoring and regulating sources of greenhouse gas emissions that cause climate change. Methane emissions control is critical to fulfilling this mandate because these emissions are not yet declining, putting continued pressure on the GHG emissions limit, as well as on any efforts to achieve deeper reductions. Both the 2008 Climate Change Scoping Plan and the subsequent First Update to the Climate Change Scoping Plan identified the oil and gas sector as a large source of GHG emissions and include the regulation of oil and gas operations covered in the proposed regulation as a potential GHG mitigation measure to help achieve the statute's goals.

Short-lived climate pollutants (SLCP), including methane (CH_4), are among the most harmful to both human health and global climate. They are powerful climate forcers that remain in the atmosphere for a much shorter period of time than longer lived climate pollutants such as carbon dioxide (CO_2). Their relative climate forcing (or impact), when measured in terms of how effectively they heat the atmosphere, can be tens, hundreds, or even thousands of times greater than that of CO_2.[1] While reducing CO_2 emissions impacts climate change over the long term, reducing emissions of SLCPs will effectively slow the rate of climate change in the near-term; therefore, reducing these emissions can have an immediate beneficial impact on climate change.

Methane is a particularly effective SLCP and is the second largest man-made contributor to GHG emissions globally. Methane is 72 times more potent than CO_2 as a GHG when considered on a twenty year time frame. Methane is responsible for about 20 percent of current global warming and is emitted from a wide range of sources with emissions increasing globally as a result of human activities related to agriculture, waste handling and treatment.[2] Oil and gas systems are responsible for approximately 15 percent of methane emissions in the state. The recently proposed SLCP strategy includes a forty percent reduction of methane by 2030 with a 40-45% reduction from the oil and gas sector as a whole by 2025.

The proposed regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities (proposed regulation) is designed to reduce emissions from both upstream (production, gathering and boosting stations, and processing) and some downstream facilities (natural gas storage and transmission compressor

[1] IPCC. 2007. Direct Global Warming Potentials. Chapter 2, 10.2.
[2] Kirschke, S. et al. 2013. Three Decades of Global Methane Sources and Sinks. Nature Geoscience.vol. 6, 813–823.

stations), which account for about four percent of statewide methane emissions.[3] GHG emissions from oil and gas pipelines and related facilities are being addressed in a separate regulatory effort in partnership with the California Public Utilities Commission (CPUC)[4].

What are we proposing?

The proposed regulation will reduce methane emissions from oil and gas production, processing, storage, and transmission compressor stations by requiring regulated entities to take actions to limit intentional (vented) and unintentional (leaked or fugitive) emissions from active and idle equipment and operations. Some methane reductions are already achieved as co-benefits of local air district regulations governing emissions of volatile organic compounds (VOC); methane is not considered to be a VOC but can be captured along with VOCs. The goal of the proposed regulation is to obtain the maximum GHG emission reductions from the sector in a technically feasible and cost-effective manner, building upon the existing regulations already being implemented by the air districts. The source categories covered under the proposed regulation currently emit approximately two and a half million metric tonnes (MMT) of CO_2e. The proposed regulation will reduce those emissions by over fifty percent. The proposal is also expected to reduce both VOC and toxic air contaminant (TAC) emissions and provide an essentially neutral NO_x impact statewide.

The provisions of the proposed regulation are:

1. Collection and use (or destruction) of methane and associated gases from uncontrolled oil and water separators and storage tanks with emissions above a set methane standard;
2. Collection and use (or destruction) of methane and associated gases from all uncontrolled well stimulation circulation tanks;
3. Leak Detection and Repair (LDAR) requirements for components, such as valves, flanges, and connectors, currently not covered by local air district rules;
4. Methane emission standards for large reciprocating compressors in addition to LDAR for the other large compressor components and smaller compressors;

[3] Upstream emissions cover emissions from production, processing, and gathering and boosting stations. Covered downstream emissions include natural gas storage and transmission compressor stations.
[4] More information on the CPUC effort can be found at: California Public Utilities Commission (CPUC). 2015. Order Instituting Rulemaking to Adopt Rules and Procedures Governing Commission-Regulated Natural Gas Pipelines and Facilities to Reduce Natural Gas Leakage Consistent with Senate Bill 1371 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M144/K999/144999228.PDF

5. Collection and use (or destruction) of methane and associated gases from specified centrifugal compressors, or replacement of higher emitting “wet seals” with lower emitting “dry seals”;
6. Use of “No bleed” pneumatic pumps and “no bleed” continuous bleed pneumatic devices with limited exemptions and restrictions on intermittent bleed pneumatic devices; and
7. Enhanced monitoring for underground natural gas storage facilities including leak detection and ambient air monitoring.
8. Reporting requirements for liquids unloading and well casing vents

Why are we proposing this action?

Methane emissions from the oil and gas industry contribute to California’s greenhouse GHG emissions and cost-effective reduction opportunities already exist and are available for use in the sector. In addition, reducing methane emissions from this sector will help slow the rate of climate change in the near-term and have an immediate beneficial impact on climate change because methane is a powerful SLCP.

Who will be subject to the proposed regulation?

Owners and operators of equipment used in the following operations will be subject to the proposed regulation:

- Onshore and offshore crude oil or natural gas production, including well stimulation activities;
- Crude oil, condensate, and produced water separation and storage;
- Natural gas underground storage;
- Natural gas gathering and boosting stations;
- Natural gas processing plants;
- Natural gas transmission compressor stations.

Oil and gas companies, public utilities, and engineering service providers are among the largest companies that would be directly impacted.

Who will enforce the regulation?

Because stationary sources in this sector have historically been regulated by local air districts, ARB staff worked with the California Air Pollution Control Officers Association (CAPCOA) and individual air districts to design the proposal so it can be implemented and enforced by both ARB and the districts. ARB staff expects that most local air districts will choose to take the lead in implementing and enforcing the regulation, with ARB serving as the backup agency, and it is our preference that the rule is implemented and enforced in this manner. However, ARB is prepared to take a lead implementation role in the event that the air district elects to let ARB serve in that role. The local air districts are more familiar with operators, conduct inspections nearby or at the same sites, and in many instances have been regulating such sources for decades. As a result, the proposal was designed to allow local districts to enter into MOUs with ARB to define implementation and enforcement responsibilities, and to share information. The proposed regulation also provides for districts to incorporate the proposed regulation into their local rules. Upon its adoption, the proposal becomes a State regulation enforceable by ARB. This limits the ability of air districts to implement less stringent requirements. ARB anticipates continuing to work closely with local air districts to ensure adequate support for the proposed regulation's implementation and enforcement.

What are the costs of the proposed regulation?

The proposed regulation would increase costs on the complying industries, which are primarily involved with oil and gas extraction. These industries pay for control equipment and services from secondary industries but may also achieve operational cost savings through recovery of natural gas captured by the proposed control strategies. ARB staff estimates the proposed regulation will cost about $22 million dollars per year including enhanced natural gas storage monitoring. The proposed regulation is expected to reduce GHG emissions by about 1.5 MMT CO_2e per year based on a 20-year horizon global warming potential (GWP). The cost per ton of CO_2e reduction is estimated to be about $17 without considering savings and $15 after savings, based on a 20-year GWP. Considering the size and diversity of the California economy, the economic impacts of the proposed regulation on the California economy are negligible, including the impact on growth of employment, investment, personal income, and production.

What are the benefits of the proposed regulation, including for Environmental Justice and Disadvantaged Communities?

Communities located in close proximity to oil and gas operations experience impacts related to these operations. Additionally, these communities are at risk for exposure to a variety of volatile organic compounds and toxics air contaminants, which are associated with oil and gas operations. Local air districts currently implement a variety of rules that reduce volatile organic compounds from the oil and gas industry with a co-benefit of methane reductions.

The proposed regulation would provide additional benefits in reductions of air pollutants including about 1.5 million metric tons of CO_2e, over 3,600 tons of VOCs, and over 100 tons of toxic air contaminants annually. The majority of all these reductions will occur in the San Joaquin Valley. Although the purpose of the regulation is to reduce methane emissions, the proposed regulation was designed to provide co-benefits and minimize or eliminate any other potential air quality impacts. While there is an essentially neutral impact on NOx emissions statewide, there is expected to be a slight decrease in NOx emissions in the San Joaquin Valley from current conditions. The San Joaquin Valley Air Pollution Control District (SJVAPCD) has notified ARB that they are considering adopting a flare minimization rule that would achieve NOx reductions from similar sources. ARB will continue to work closely with the district to monitor the development of regulations from the plan and address any remaining NOx concerns.

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LIST OF ACRONYMS

AAQS	Ambient Air Quality Standards
AB	Assembly Bill
APCD	Air Pollution Control District
AQMD	Air Quality Management District
ARB or Board	California Air Resources Board
BAU	Business as Usual
BLM	Bureau of Land Management
BTEX	Benzene, Toluene, Ethylbenzene, and Xylenes
Cal/EPA	California Environmental Protection Agency
CAPCOA	California Air Pollution Control Officers Association
CDFW	California Department of Fish and Wildlife
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CH_4	Methane
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalents
CPUC	California Public Utilities Commission
CPUC	California Public Utilities Commission
CTG	Control Technology Guidance
DOF	Department of Finance
DOGGR	Department of Conservation, Division of Oil, Gas, and Geothermal Resources
EA	Environmental Analysis
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
F-gases	Fluorinated Gases
GHG	Green House Gas
GSP	Gross State Product
GWP	Global Warming Potential
H_2S	Hydrogen Sulfide
HAP	Hazardous Air Pollutant
HC	Hydrocarbon
HF	Hydraulic Fracturing
HFC	Hydro-fluorocarbon
I&M	Inspection and Maintenance
ICF	ICF International
ISOR	Initial Statement of Reason
LDAR	Leak Detection and Repair
MCF	Thousand Cubic Feet
MMT	Million Metric Tonnes
MOA	Memoranda of Agreement
MOU	Memorandum of Understanding

MRR	Mandatory Reporting Regulation
MT	Metric Ton
$MTCH_4$/Yr	Metric Ton of Methane per Year
N_2O	Nitrous Oxide
NAAQS	National Ambient Air Quality Standards
NG	Natural Gas
NGO	Non-governmental Organization
NO_x	Nitrogen Oxides or Oxides of Nitrogen
NSPS	New Source Performance Standard
OGI	Optical Gas Imaging
PM	Particulate Matter
PYs	Person Years
RACT	Reasonably Available Control Technology
REC	Reduced Emissions Completion
REMI	Regional Economic Models, Inc.
RWQCB	Regional Water Quality Control Boards
SB	Senate Bill
scfh	Standard Cubic Feet per Hour
scfm	Standard Cubic Feet per Minute
SJVAPCD	San Joaquin Valley Air Pollution Control District
SLCP	Short Lived Climate Pollutants
SO_2	Sulfur Dioxide
SoCal Gas	Southern California Gas
SOx	Sulfur Oxides or Oxides of Sulfur
SRIA	Standard Regulatory Impact Assessment
SRIA	Standardized Regulatory Impact Assessment
TAC	Toxic Air Contaminant
TPY	Tons Per Year
UIC	Underground Injection Control
USDA	U.S. Department of Agriculture
USFWS	U.S. Fish and Wildlife Service
VCS	Vapor Collection System
VOC	Volatile Organic Compounds
VRS	Vapor Recovery System
VRU	Vapor Recovery Unit
WS	Well Stimulation
WSPA	Western State Petroleum Association

I. INTRODUCTION

A. BACKGROUND CLIMATE CHANGE PROGRAMS

1. AB 32

On September 27, 2006, Governor Schwarzenegger signed Assembly Bill 32 (AB 32), The California Global Warming Solutions Act of 2006 (Health & Safety Code §§38500-38599). AB 32 requires a reduction of greenhouse gas (GHG) emissions to 1990 levels by 2020 and designates the California Air Resources Board (ARB) as the lead agency for implementing AB 32. AB 32 provided direction and broad authority to create a comprehensive multi-year program to limit California's GHG emissions and initiate the transformations required to achieve the State's long-range climate objectives.

AB 32 charges ARB with achieving statewide GHG emissions targets by 2020, with maintaining that target, and with continuing the maximum technologically feasible and cost-effective GHG reductions going forward. As part of the strategy to reach and maintain the 2020 emission target, and secure continued reductions, ARB identified the oil and gas sector as a large source of GHG emissions – primarily methane. Both the 2008 Climate Change Scoping Plan and the subsequent First Update to the Climate Change Scoping Plan include the regulation of oil and gas operations covered in the proposed regulation as a potential GHG mitigation measure. Unless methane emissions, which now continue at high levels, are controlled, they will put continued pressure on the statewide GHG limit, as well as complicate any efforts to achieve deeper emissions reductions in the future. Steps therefore must be taken to control these emissions in order to fulfill AB 32's mandates.

Accordingly, this regulation covers upstream emissions (production, gathering and boosting stations, and processing) as well as natural gas storage and transmission compressor stations (collectively "oil and gas"). This regulation does not cover the petroleum refining sector. Further, GHG emissions from oil and gas pipelines and related facilities are being addressed in a separate regulatory effort in partnership with the California Public Utilities Commission (CPUC).

In 2009, ARB initiated a survey of the oil and gas industry, collecting information on sources such as compressor seals, storage tanks, valves, flanges, and connectors. The survey included combustion related emissions from equipment (equipment burning fuel for energy) as well as vented and fugitive sources, which are intentional and unintentional releases of gases to the atmosphere, respectively. The survey is the most comprehensive dataset that exists for California's oil and gas industry. No other dataset, federal or statewide, contains as much detailed information about the industry in the state. The findings from this survey provide the basis for the proposed regulation, which reduces vented and fugitive emissions from oil and gas production, processing, storage, and transmission compressor stations. ARB has incorporated additional or supplemental data where appropriate.

2. Short Lived Climate Pollutants

Short-lived climate pollutants (SLCP), including methane (CH_4), black carbon (soot), and fluorinated gases (F-gases, including hydro-fluorocarbons, or HFCs), are among the most harmful to both human health and global climate. They are powerful climate forcers that remain in the atmosphere for a much shorter period of time than longer lived climate pollutants such as carbon dioxide (CO_2). Their relative climate forcing (or impact), when measured in terms of how they heat the atmosphere, (see explanation of global warming potential in footnote 10) can be tens, hundreds, or even thousands of times greater than that of CO_2.[5] While reducing CO_2 emissions limits climate change over the long term, reducing emissions of SLCPs will help slow the rate of climate change in the near-term; therefore, reducing these emissions can have an immediate beneficial impact on climate change.

Methane has a global warming potential 72 times that of CO_2, on a 20-year timeframe, and is the principal component of natural gas[6]. Methane emissions also contribute to background ozone in the lower atmosphere. Such ground-level ozone not only contributes to ground level "smog" but ozone is also a powerful GHG.

Methane, the second largest anthropogenic, or man-made contributor to GHG emissions globally, is emitted from a wide range of fugitive sources and biological processes. Methane emissions are increasing globally as a result of human activities related to agriculture, waste handling and treatment, and oil and gas production, and are responsible for about 20 percent of current global warming.[7] Agriculture represents the largest methane source in California, accounting for nearly 60 percent of methane emissions (Figure 1). Landfills are the next largest source of methane at 20 percent of statewide methane emissions. Oil and gas systems contribute approximately 13 percent of statewide methane emissions, with wastewater treatment and other industrial and miscellaneous sources comprising the remainder of emissions. The proposed regulation is designed to reduce methane emissions from upstream and some downstream oil and gas activities within

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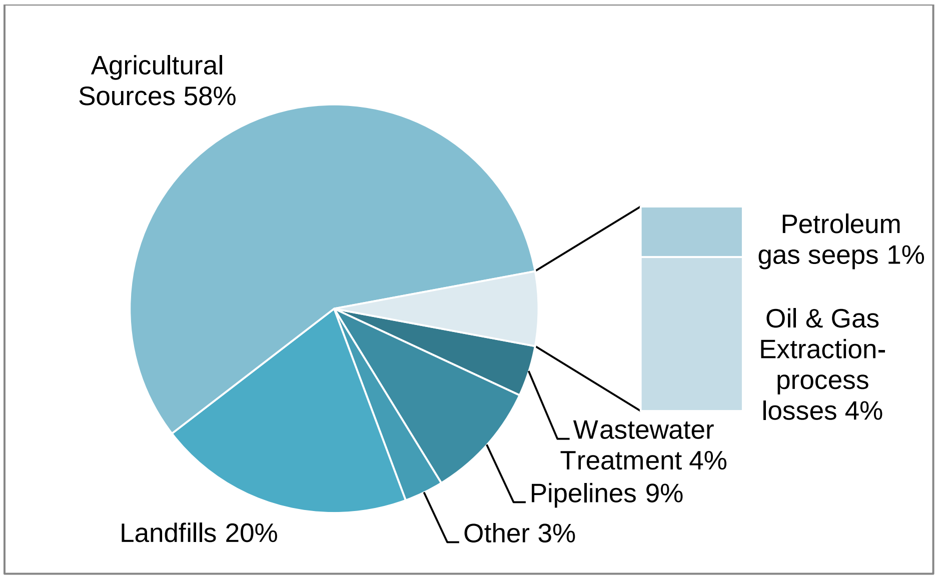
[5] See footnote 1.
[6] Staff used the 20 year global warming potential from the Fourth Assessment Report, which is 72. The Fifth Assessment report estimates methane is at least 84 times as potent as carbon dioxide on a 20 year timeframe. IPCC. 2008. Climate Change 2007. Synthesis Report. IPCC Fourth Assessment Report: Climate Change 2007. http://www.ipcc.ch/pdf/assessment-report/ar4/syr/ar4_syr_full_report.pdf And IPCC. 2015. Climate Change 2014. Synthesis Report. IPCC Fifth Assessment Report: Climate Change 2014. http://ar5-syr.ipcc.ch/ipcc/ipcc/resources/pdf/IPCC_SynthesisReport.pdf
[7] See footnote 2.

California, which accounts for about four percent of statewide methane emissions[8].

The regulation supports a larger, on-going, effort to reduce short-lived climate pollutants. Pursuant to Senate Bill 605 (SB 605) (Health & Safety Code § 39730), ARB is proposing a comprehensive approach to reduce methane through the proposed Short-lived Climate Pollutant Reduction Strategy.[9] As noted in that report, ARB is proposing to reduce methane emissions from oil and gas systems (oil and gas production, processing, storage, and natural gas transmission and distribution) by 40-45 percent in 2025, matching federal commitments. Thus, the proposed regulation helps to achieve the goals identified in the proposed SLCP Reduction Strategy.

Figure 1: California 2013 Methane Emission Sources (118 MMTCO$_2$e)[10]



[8] Upstream emissions cover emissions from production, processing, and gathering and boosting stations. Covered downstream emissions include natural gas storage and transmission compressor stations. In Figures 6 and 7, Oil and Gas Extraction process losses includes all the upstream emissions, not just production.
[9] ARB. 2016. Proposed Short-Lived Climate Pollutant Reduction Strategy in California.
[10] See footnote 9. Using the 20-yr global warming potential from the IPCC's Fourth Assessment Report (AR4) for methane. The Intergovernmental Panel on Climate Change (IPCC) developed the concept of global warming potential (GWP) as an index to evaluate the climate impacts of different GHGs, including SLCPs. This metric provides a comparison of the ability of each GHG to trap heat in the atmosphere relative to CO_2 over a specified time horizon. Current practice in most of the world for developing GHG emission inventories, including California's GHG inventory, is to use GWP values from the 4th Assessment Report of the IPCC (AR4), which was released in 2007. California's inventory generally uses GWPs over a 100-yr timeframe. However, the use of GWPs with a time horizon of 20 years better captures the importance of the SLCPs and gives a better perspective on the speed at which SLCP emission controls will impact the atmosphere relative to CO_2 emission controls. Thus, the emission inventory and estimated reductions presented later in this ISOR are calculated using 20-year GWP for methane.

B. BACKGROUND – AIR DISTRICTS

Under State law, ARB and local air districts operate within a cooperative legal framework for controlling air pollution from a variety of sources. There are 35 air districts as shown in Figure 2. Each jurisdiction's authority is based on the type of air pollutants and sources involved.

For smog-forming pollutants including volatile organic compounds, or VOCs, ARB has authority over mobile and area wide sources, such as vehicles, fuels, and consumer products, while the local districts have responsibility over stationary sources, including oil and gas operations. For portable equipment, the State shares jurisdiction with the air districts.

There are two significant exceptions to this general framework. First, with regard to greenhouse gases, AB 32 gives ARB broad authority to regulate GHGs from both mobile, stationary, and area wide sources. This regulation would be implemented under AB 32 as mentioned earlier. The other major area where ARB has authority over stationary sources involves toxic air contaminants, where the regulation of toxic air contaminants is a responsibility shared by ARB and the local districts.

For air districts with significant oil production, each district has rules aimed to reduce particulate matter less than 2.5 microns in diameter ($PM_{2.5}$) as well as oxides of nitrogen (NO_x) and volatile organic compound (VOC) emissions specifically from the oil and gas sector. These rules do not regulate methane directly from the sector, so the proposed regulation is designed to address those sources that are not controlled by existing district rules. ARB has used the district rules as a starting point, particularly for leak detection and repair, where districts have been implementing programs for decades.

C. CALIFORNIA'S OIL AND NATURAL GAS RESOURCES

Methane emissions from California's oil and gas sector are substantial in part because the state is a large oil and gas producer. The top crude oil producing states are Texas, North Dakota, California, Alaska, New Mexico, and Colorado, representing a combined two-thirds of the total crude oil production in the U.S in September 2015.[11] Texas is also the largest natural gas producer in the U.S.;[12] California is at number fifteen on the natural gas producer list, based on 2014 data. According to the U.S. Energy Information Administration (EIA), California ranked third in the nation in crude oil production in 2014, despite an overall decline in production rates in California since the mid-1980s (excluding Federal offshore areas).

[11] U. S. EIA. 2015. Rankings: Crude Oil Production, December 2015 (thousand barrels).
[12] U. S. EIA. 2014. Rankings: Natural Gas Marketed Production, 2014 (million cu ft).

California has nine main petroleum systems,[13] named for the rock where the resource has been generated (source rock) that produce crude oil and natural gas (Table 1). The most prolific oil-producing area in California is the San Joaquin Basin[14] in the southern half of the Central Valley; natural gas reserves and production are located primarily in geologic basins in the Central Valley, the coastal basins onshore in Northern California and offshore along the Southern California Coast. The Monterey Formation, which stretches across the lower part of the state, is the primary source of oil and gas resources in California.

Table 1: California's main petroleum systems

Name	Type	General Location
Monterey	oil	Los Angeles, Ventura, Santa Maria, and San Joaquin Basins, and Point Arena, Mendocino County
Eel River	gas	Humboldt Basin
Kreyenhagen	oil	San Joaquin Basin
Miocene	oil	Los Angeles, Santa Barbara, Ventura, and Santa Maria Basins Offshore
Moreno	oil	San Joaquin Basin
Forbes	gas	Sacramento Basin
Starkey	gas	Sacramento Basin
Hornbrook	gas	Sacramento Valley
Domengine	gas	Sacramento and San Joaquin Valleys

Oil production in California has been occurring since before 1900, and much of the remaining reserves require additional effort to produce including enhanced oil production techniques such as steam-enhanced production, and well stimulation treatments such as acid fracturing, acid matrix and hydraulic fracturing. Oil production in California generally produces large volumes of water and may contain "associated gas" (gas dissolved in oil and produced as a byproduct of crude oil production). California also produces gas not associated with oil production, referred to as both non-associated gas and dry gas. Non-associated gas may produce some natural gas condensate, which is a gaseous hydrocarbon mixture that condenses out of the natural gas when the pressure is sufficiently reduced. The condensate includes butane, propane, and other substances.

[13] A petroleum system includes all those geologic elements and processes that are essential for an oil and gas deposit to exist in nature. These basic elements include a petroleum source rock, migration path, reservoir rock, seal, and trap; and the geologic processes that create each of these basic elements. (USGS. 1988. Petroleum Systems of the United States.)

[14] A basin is a low area in the Earth's crust, of tectonic origin, in which sediments have accumulated (USGS. 1980. Definitions for the Geologic Provinces.). Hydrocarbon generation can occur within the basin if the source rocks are rich hydrocarbon and occur at an appropriate depth, temperature, and pressure.

California has a large oil and gas industry with more than 50,000 oil and 1,500 gas wells, including offshore platforms. Figure 2 depicts the above-noted oil and natural gas producing regions of California. Each dot on the map represents a currently permitted well in operation as of February 2016. The majority of the oil wells are located in Central and Southern California with most of the gas fields located in Northern California. An extensive network of oil and gas pipelines within the State transports California's natural gas and crude oil throughout the State.

The San Joaquin Valley Air Pollution Control District (APCD) is home to seven of the top ten largest oil fields in California. Combined, these seven oil fields produced 60 percent of the State's total oil production in 2014.[15] In addition, five fields in Kern County produced nearly 70 percent of the state's associated gas in 2014.

California's remaining top oil producing fields are in the South Coast Air Quality Management District (AQMD), Monterey Bay Unified APCD, and Ventura County APCD and produce 11 percent of the state's total oil production. The top producing non-associated gas fields are located in northern California are in Yolo-Solano, Glenn, Colusa, and Feather River air districts, and produce almost 60 percent of the state's total non-associated gas.[16] The air districts and the oil and gas facility types within each district are depicted in Figure 2.

Below are the preliminary 2014 state totals for oil and gas production in California, both onshore and offshore.

Table 2: Preliminary 2014 California oil and gas production levels [17]

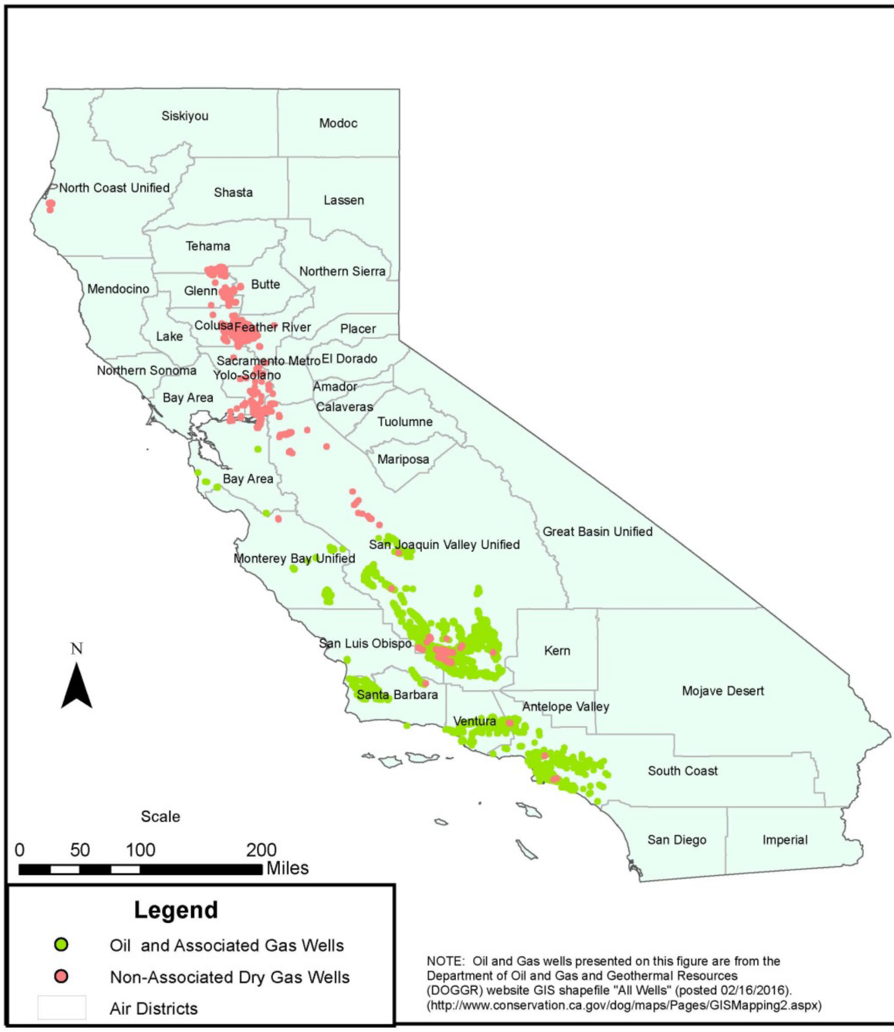
Oil (bbl)*	Associated gas (Mscf)**	Non-associated gas (Mscf)	Water (bbl)	Condensate (bbl)
205,287,622	159,511,531	34,963,640	3,264,502,956	68,471

*Unit of volume for crude oil and petroleum products. One barrel equals 42 US gallons.
**Thousand cubic feet

[15] DOGGR. 2015. 2014 Preliminary Report of California Oil and Gas Production Statistics.
[16] Ibid.
[17] Ibid.

Figure 2: Oil and Natural Gas Industry Sector by Air District

Figure 3: California Non-Associated Natural Gas Wells & Oil and Associated Gas Wells



D. OVERVIEW OF EMISSIONS AND REDUCTIONS

GHG emissions occur throughout the oil and gas sector, from production through processing and transmission and distribution. Emissions occur from intentional emissions (venting) that is part of normal operations including open tanks and equipment venting for safety or operational reasons. Emissions can also be due to unintentional leaks that occur at covered tanks, valves, or other components throughout the system. The details on the emissions covered under the proposal are outlined in the Technical Assessment chapter, as well as Appendix D.

As noted, the local air districts have rules and regulations to limit VOC and NO_x emissions because they are precursors of ground-level ozone. Many of the VOC controls also reduce methane as a co-benefit, since both VOCs and methane are found in the raw oil and gas and controlling VOCs will also reduce methane emissions. However, the district rules do not apply once the gas has been processed to the point that not many VOCs remain in the gas (generally less than 10%). For remaining gas streams that have fewer VOCs, the proposed regulation will reduce methane with a co-benefit of reducing the remaining VOCs as well. In 2015, U.S. EPA proposed additional federal measures that could address methane primarily at new oil and natural gas sources, with coverage at some existing sources, finalizing these measures in 2016. These additional actions to reduce methane from the oil and gas sector should also reduce VOC and toxic air contaminant emissions. In 2016, U.S. EPA announced efforts to consider similar measures for existing sources but that measure is in the information gathering stage.[18]

In recent years, there has been a significant amount of literature published on emissions from the oil and gas sector. Several studies have suggested that methane emissions are underestimated from this sector based on atmospheric studies.[19][20] However, some recent literature supports U.S. EPA's oil and gas emissions estimates and at least one sector specific study focused on distribution pipelines found lower emissions than expected.[21] In April 2016, U.S.EPA adjusted their GHG emission estimates for the sector with significant increases in the production sector and decrease for transmission and distribution.[22] ARB staff has reviewed this recent information at a high level and believes that the proposed regulation is consistent with the revised numbers, and there is a sufficiently robust and defensible basis for this proposal. ARB's in-depth industry survey provided much more information than is available at the federal level, and U.S.EPA's estimates were similar or larger for most of the

[18] U. S. EPA. 2016. Reducing Methane Emissions from the Oil and Gas Industry.
[19] Brandt, A. R., et al. 2014. Methane Leaks from North American Natural Gas Systems. Science. Vol. 343.
[20] Miller, S. M., et al. 2013. Anthropogenic Emissions of Methane in the United States. Proceedings of the National Academy of Sciences. December 10, 2013
[21] Allen, David T., et al. 2015. Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers.
[22] U. S. EPA. 2016. U.S. Greenhouse Gas Inventory Report: 1990-2014.

sectors controlled to be under this proposed regulation, which would result in similar or more cost-effective measures.

Implementing the measures in the proposed regulation would reduce methane emissions by 40-45 percent in 2025. Additional opportunities may emerge to further reduce emissions and will be considered when they do.

1. Super Emitters

Emissions from components are not distributed uniformly throughout the sector, recent studies of natural gas facilities have shown a significant fraction of methane emissions can be attributed to a small fraction of sites or sources.[23] [24] [25] [26] [27] [28] The emissions associated with these "super-emitters" are thus important to detect and repair. Figure 4 below, illustrates one production sector example where, according to Allen et al, the top 19% of emitting pneumatic devices accounts for 95% of the emissions from pneumatics. Studies investigating methane emissions from super emitters in the natural gas system have most recently been conducted outside of California. Efforts by ARB and the California Energy Commission (CEC) are underway to investigate such emissions by using aircraft to conduct a survey of methane sources in California, including oil and gas.

[23] See footnote19.

[24] See footnote 21.

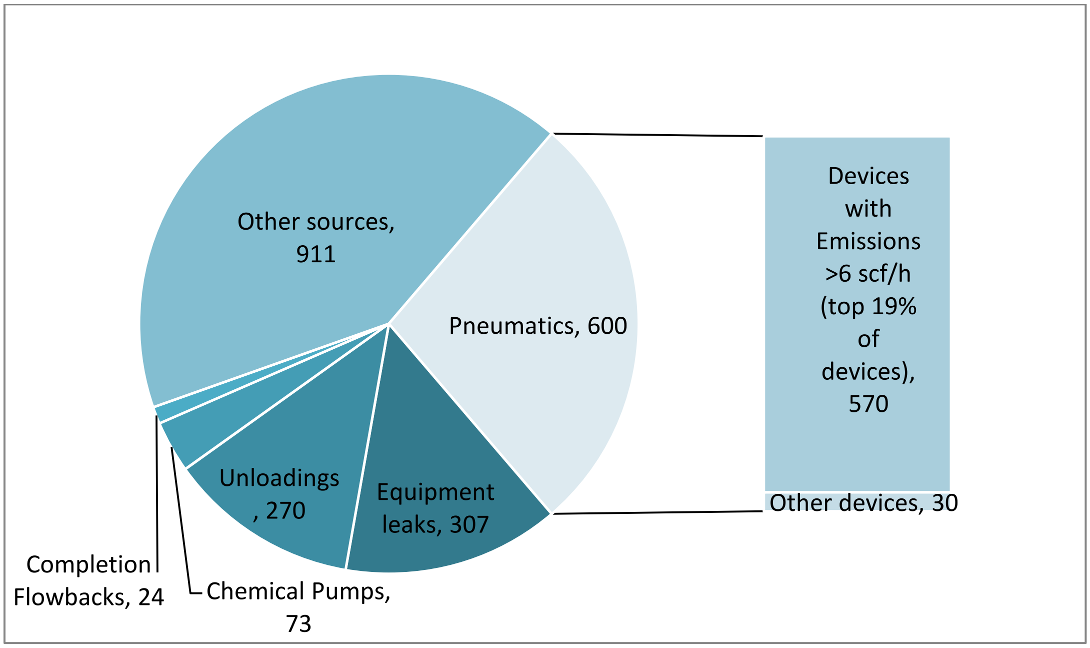
[25] Lamb, Brian K. et al. 2015. Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States. Environmental Science & Technology.

[26] Zavala- Araiza, Daniel, et al. 2015a. Toward a Functional Definition of Methane Super-Emitters:Application to Natural Gas Production Sites. Environmental Science & Technology. Vol. 49, Pages 8167−8174. .

[27] Zavala- Araiza, Daniel, et al. 2015b. Reconciling divergent estimates of oil and gas methane emissions. Proceedings of the National Academy of Sciences (PNAS).

[28] Zimmerle, Daniel J., et al. 2015. Methane Emissions from the Natural Gas Transmission and Storage System in the United States. Environmental Science & Technology.

Figure 4: Methane Emission by Component, Oil and Natural Gas Systems.[29]



2. Aliso Canyon

In addition to super-emitters, very large unusual and unexpected leaks can occur. One recent example is the incident at Aliso Canyon. On October 23, 2015, Southern California Gas (SoCal Gas) informed the State of a natural gas leak at its Aliso Canyon natural gas storage facility. After several attempts to stop the leak, on February 11, 2016, SoCalGas temporarily controlled the leak by injecting mud from a relief well intersecting the bottom of the leaking well. February 18, 2016, state officials, including the Department of Conservation, Division of Oil, Gas, and Geothermal Resources (DOGGR), confirmed the well has been permanently sealed. However, preliminary measurements suggest a total of 94,500 tons of methane was released.[30] Because of this incident, ARB has clarified requirements and added an additional provision to the proposed regulation specifying monitoring for the early detection of leaks.

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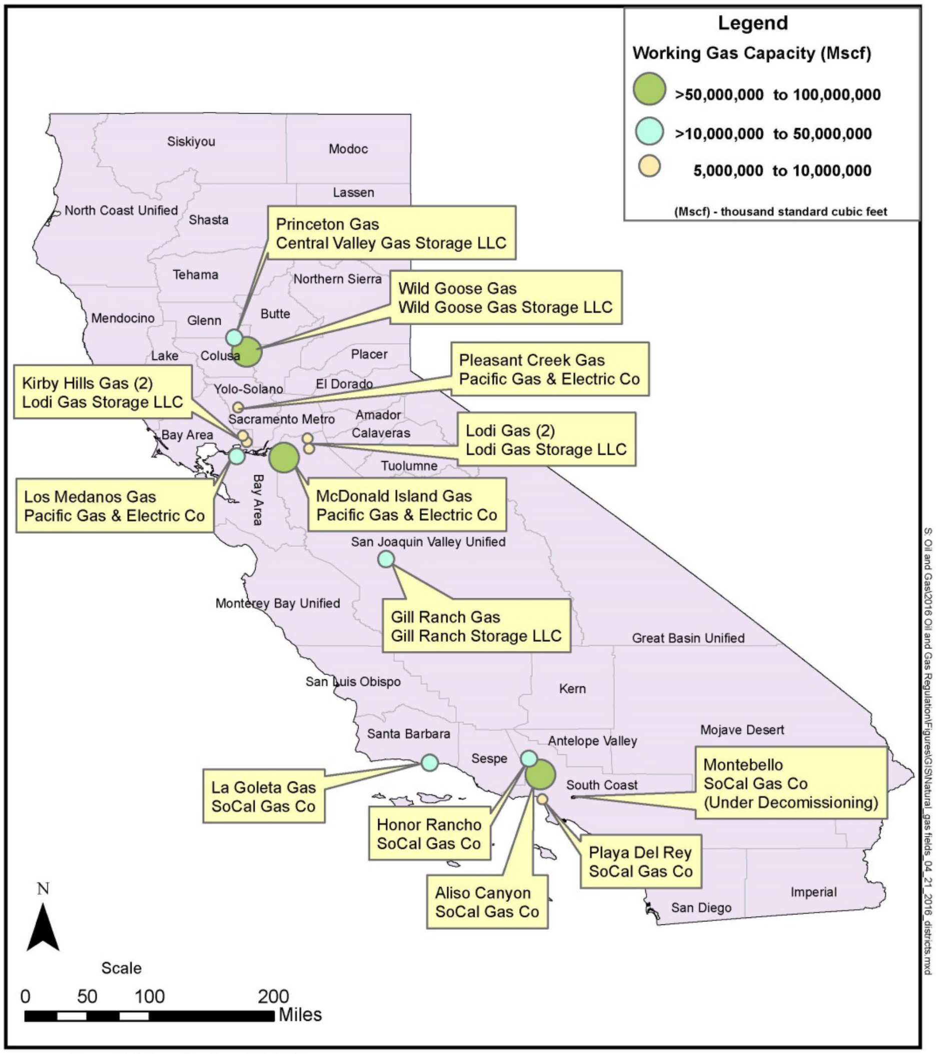
[29] See footnote 21.

[30] ARB. 2016. Aliso Canyon Natural Gas Leak. Preliminary Estimate of Greenhouse Gas Emissions (As of April 5, 2016). http://www.arb.ca.gov/research/aliso_canyon/aliso_canyon_natural_gas_leak_updates-sa_flights_thru_April_5_2016.pdf

Figure 5: California Natural Gas Storage Facilities, Operating Utility, and Air District Boundaries



Capacity Information from EIA, 2014.
http://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RP7

E. DEVELOPMENT PROCESS FOR THE PROPOSED REGULATION

Staff evaluation of methane emissions from the oil and gas sector began with the 2009 Survey, noted earlier, with an acknowledgement of the importance of the oil and gas sector in the original Scoping Plan. Staff conducted a comprehensive, detailed survey of the industry, which provided a basis for regulatory development. During the informal rulemaking process, Staff conducted multiple public workshops and numerous meetings with individual stakeholders. Below is a timeline of the public actions taken leading to this proposal. Each of the meetings below included opportunities for public comment, which were considered when developing the proposed regulation.

Table 3: Dates of Development Meetings and Workshops

Date	Meeting
April 11, 2008	Workshop on Regulatory Concepts
2009	Conducted Survey
December 8, 2009	Workshop on Survey Results
December 2011	Posted Survey Results Report
November 2013	Posted Revised Survey Results Report
August 25, 2014	Oil and Gas Rulemaking Workshop #1
December 9, 2014	Oil and Gas Rulemaking Workshop #2
April 27, 2015	Oil and Gas Rulemaking Workshop #3 with Proposed Draft Regulatory Language (Sacramento)
April 29, 2015	Oil and Gas Rulemaking Workshop #4 with Proposed Draft Regulatory Language (Bakersfield)
February 4, 2016	Oil and Gas Rulemaking Workshop #5 with Proposed Draft Regulatory Language (Sacramento)

For each of the rulemaking meetings, over 4000 individuals or companies were notified and invited to participate. Each of these meetings was well attended by a variety of stakeholders, representing oil and gas production and processing companies, natural gas storage facilities, public utilities, non-governmental organizations (NGOs), and other State agencies. Notices for the workshops and associated materials, were posted to ARB's Oil and Gas webpage at: http://www.arb.ca.gov/cc/oil-gas/oil-gas.htm, and emailed to subscribers of our "oil and gas" listserve. All rulemaking workshops were streamed to remote attendees by webcast.

In addition to the public meetings, staff held many meetings with stakeholders, attended relevant meetings; conducted district, industry, and NGO working group meetings, and exchanged technical information with various parties on a regular basis. The proposal benefitted from the extensive feedback based upon these communication.

Staff also conducted a Standardized Regulatory Impact Assessment (SRIA). As required by Senate Bill 617 (Chapter 496, Status of 2011), ARB conducted a

SRIA and received public feedback and comments from the Department of Finance.

As part of the SRIA process, ARB solicited public input on alternative approaches, including any approach that may yield the same or greater benefits than those associated with the proposed regulation, or that may achieve the goals at lower cost. The SRIA summary is included as Attachment E and posted at: http://www.dof.ca.gov/research/economic_research_unit/SB617_regulation/Major_Regulations/documents/Oil_and_Gas_SRIA.PDF

F. ORGANIZATION OF THIS REPORT

The remainder of this report is organized into 11 chapters with 5 appendices. It begins with a background chapter followed by a description of the proposed regulation with the summary and rationale, description of the implementation and funding, description of other related mandates, a technology assessment, an environmental assessment, and an economic assessment. The appendices include the proposed regulation order, economic analysis, environmental analysis, emission estimate calculations, and the standardized regulatory impact analysis (SRIA).

II. STATEMENT OF REASONS

A. DESCRIPTION OF PROBLEM PROPOSAL IS INTENDED TO ADDRESS

ARB has identified the oil and gas sector as a large source of GHG emissions. Both the 2008 Scoping Plan and the subsequent First Update to the Scoping Plan include the regulation of oil and gas operations covered as a potential GHG mitigation measure. Unless emissions from the sector are controlled, they will continue to be substantial, making it more difficult to maintain the state GHG emission limit imposed by AB 32, and will also complicate efforts to further reduce emissions, as AB 32 and multiple executive orders require. emissions of fluorinated gases are projected to grow rapidly through 2030. Similarly, current projections indicate methane will not decline in the absence of successful methane control measures. If ARB does not take near-term action to stop methane emissions growth, it will be increasingly difficult to maintain the 2020 greenhouse gas limit, much less continue progress. Accordingly, methane emissions from the sector must be reduced. This regulation covers upstream emissions (production, gathering and boosting stations, and processing) as well as natural gas storage and transmission compressor stations. GHG emissions from petroleum refineries are not covered under this proposal, and oil and gas pipelines and related facilities are being addressed in a separate regulatory effort conducted by the California Public Utilities Commission (CPUC) in partnership with ARB.

Methane, the second largest man-made contributor to GHG emissions globally, is emitted from a wide range of fugitive sources and biological processes. Methane emissions are increasing globally because of human activities related to agriculture, waste handling and treatment, and oil and gas production. Cumulatively, methane emissions are responsible for about 20 percent of current global warming.[31]

In California, oil and gas systems are responsible for approximately 15 percent of methane emissions in the State. The proposed regulation is designed to reduce methane emissions from upstream and some downstream oil and gas activities within California, which accounts for about four percent of statewide methane emissions[32].

B. PROPOSED SOLUTIONS TO THE PROBLEM – BACKGROUND

The following sections illustrate and describe, in plain English, various aspects of the oil and gas sector in California.

[31] See footnote 2.

[32] Upstream emissions cover emissions from production, processing, and gathering and boosting stations. Covered downstream emissions include natural gas storage and transmission compressor stations.

1. Oil and Gas Processes Addressed by the Proposed Regulation

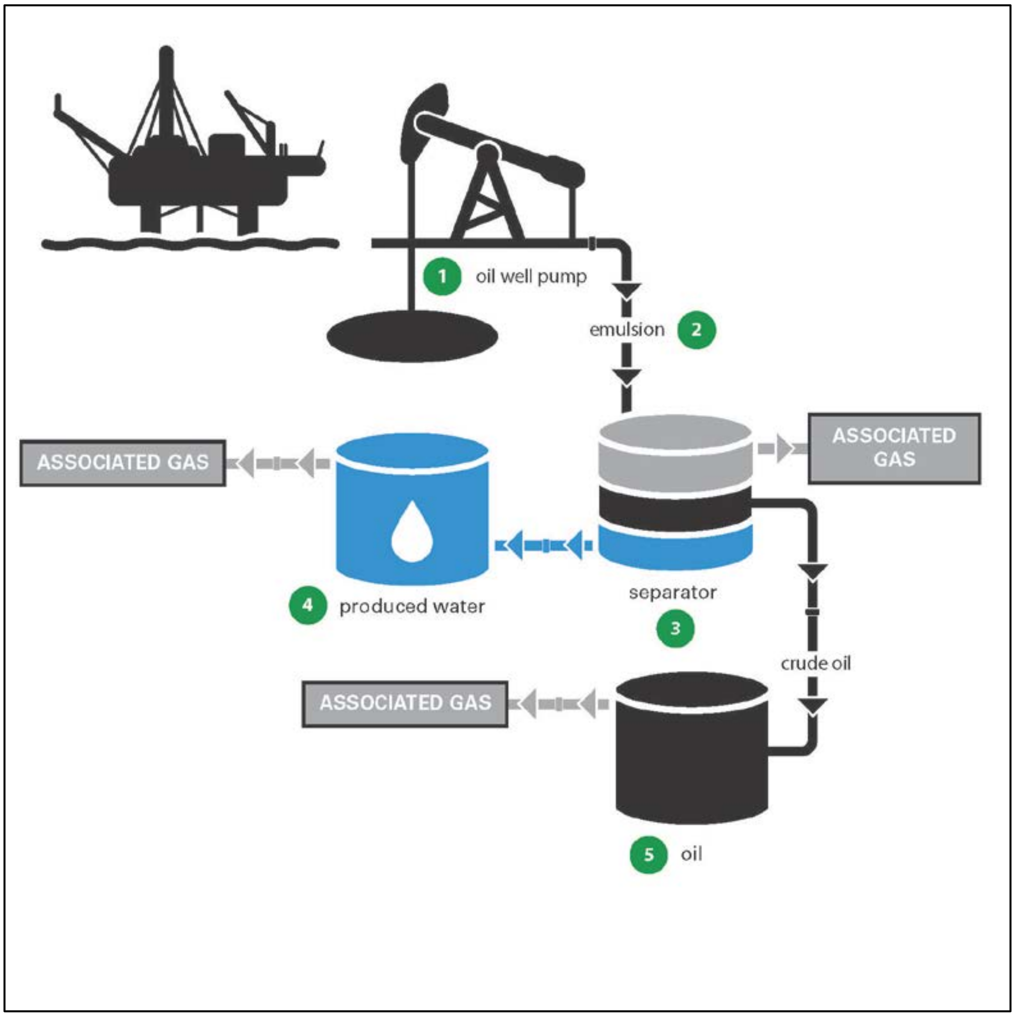
The proposed regulation addresses vented and fugitive emissions generated by processes at facilities in the following sectors:

- Onshore and offshore crude oil or natural gas production,
- Crude oil, condensate and produced water separation and storage;
- Natural gas gathering and boosting stations;
- Natural gas processing plants;
- Natural gas transmission compressor stations; and
- Natural gas underground storage.

The proposed regulation establishes emission standards for active and idle equipment and components at these facilities. Depending on the equipment or component, control mechanisms include vapor recovery, leak detection and repair (LDAR), and equipment replacement. Additionally, the proposed regulation includes monitoring at underground natural gas storage facilities for the early detection of large leaks or well failures. Storage facility monitoring provisions were added to the proposed regulation in response to the catastrophic release that occurred at the Aliso Canyon natural gas storage facility in late 2015-early 2016.

The following sections describe the crude oil and natural gas systems that are addressed in the proposed regulation and identify the equipment and components at each facility covered under the proposed regulation. These systems are further illustrated in Figures 6 through 9. Parenthetical numbers in the text refer to the figure and associated number. For example: (6, 1) refers to component 1 on Figure 6 (oil well pump), while 8-3 refers to component 3 on Figure 8 (water/condensate tank).

Figure 6: Diagram of a Crude Oil System



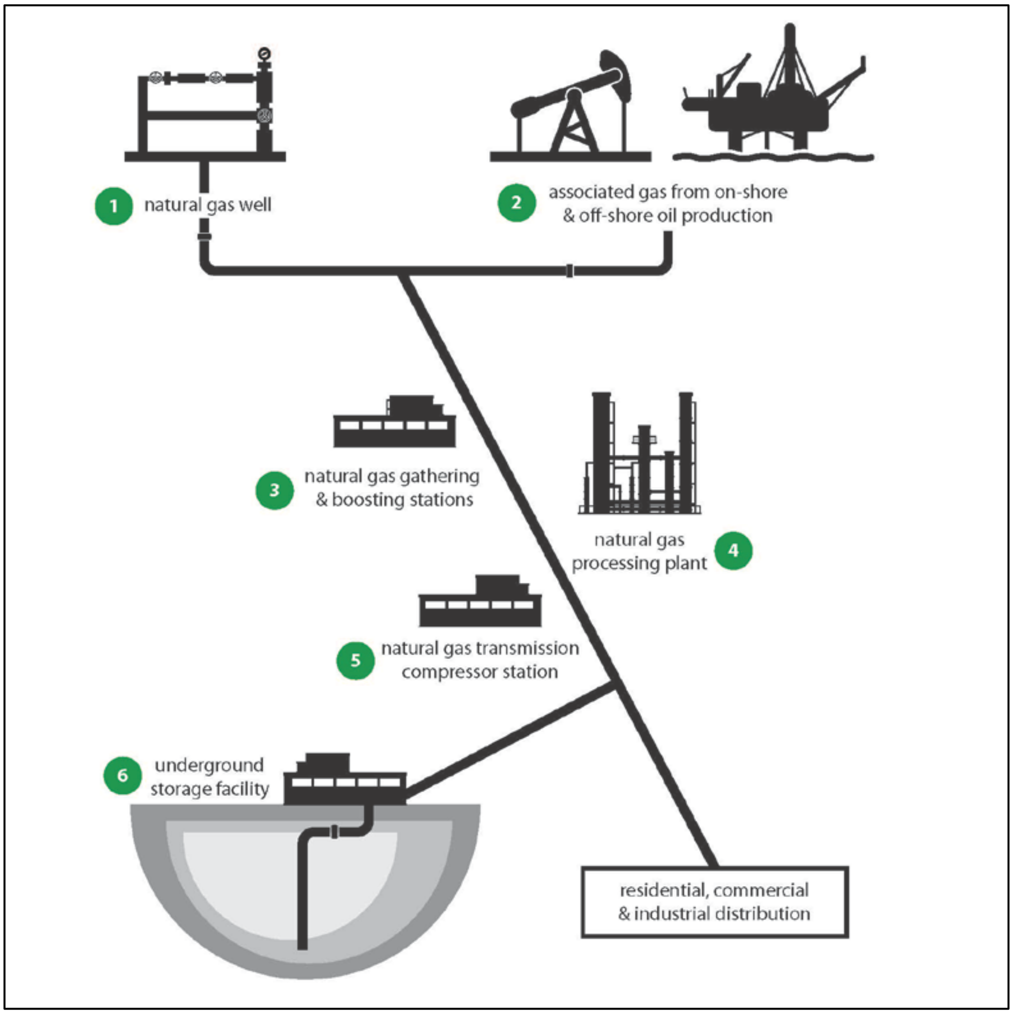
a) Oil and Gas Production

Onshore wells are drilled on a prepared surface known as a drill or production pad (6, 1). During well drilling, tanks are most commonly used to temporarily collect drilling fluids; however, a temporary pit or sump may be constructed to contain drilling fluids. Once a well has been drilled and cemented, the well completion phase begins. Well completions on a new well include casing, cementing, perforating, gravel packing, and installing a production tree. Once the casing is perforated, well stimulations such as acid fracturing, acid matrix, or hydraulic fracturing may be conducted. Well stimulation operations are performed on hydrocarbon producing wells for purposes of enhancing production by increasing the permeability of the geologic formation. These operations include the use of well stimulation fluids which can include acids such as hydrofluoric acid or a variety of other chemicals. If well stimulation occurs, a flush of the well and reservoir may recover fluids (Figure 9) that include reservoir emulsion, well stimulation treatment fluid, additives, and produced water. Recently adopted regulations, California Code of Regulations Section 1786 (a)(4), prohibit the storage of well stimulation treatment fluid, additives, and produced water from a well that has had a well stimulation treatment in sumps or pits; all such fluids, must be stored in containers.

The most common well stimulation treatment used in California is hydraulic fracturing. The proposed regulation would require controls on “circulation tanks” (8, 2), which are tanks or portable tanks used to circulate, store, or hold liquids or solids from a crude oil or natural gas well during or following a well stimulation treatment. They are used to clean out sand from the system after hydraulic fracturing. The potential control methods required in the proposed regulation include a vapor recovery system, which would be subject to leak detection and repair (LDAR). Well stimulation treatments occur primarily on new crude oil production wells in California.

An oil well is completed with a pumping unit (unless it is free flowing), and connected by piping (flow lines and gathering lines) (6, 2) to production facilities that may include separators (6, 3), tanks (6, 4-5), and testing and shipping facilities. Depending on the type of recovery method used, there may also be facilities for generating and distributing steam, and injection wells for injecting steam and/or water. After an oil or gas well is put into production, an emulsion is brought to the surface. The emulsion primarily includes oil, water, and often associated gas. Flow lines or a bulk header carries the emulsion from the wellhead to a central processing facility or production platform. This combination of components is referred to as the gathering system; it will be subject to LDAR under the proposed regulation. The gathering system feeds into the oil and gas separation system.

Figure 7: Diagram of a Natural Gas System

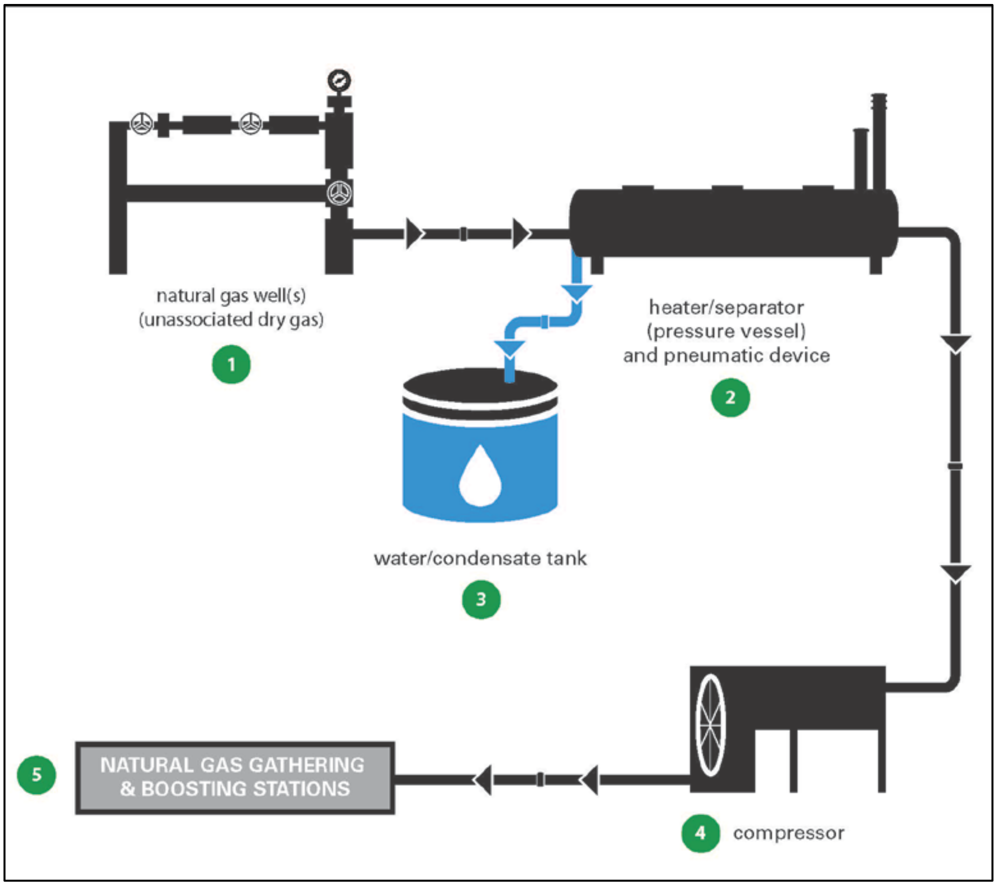


A dry gas well (8, 1) is completed with piping (flow lines and gathering lines) to a heater/separator (pressure vessel) (8, 2). The wellhead, piping and pressure vessel will be subject to LDAR under the proposed regulation. The emulsion produced from the well primarily includes gas, water, and condensate; however, in California condensate is not generally found in large volumes.

The emulsion flows from the wellhead to the heater/separator where water is separated from the gas. Emulsions from dry gas wells are often routed to one heater/separator. Piping moves wastewater to a water storage tank where, if present, residual condensate is separated out by gravity (8, 3). The gas is then routed to a compressor (8, 4) to be moved from the production facility to the gathering and boosting station (7, 3).

The wellhead, piping, pressure vessel, and compressor will be subject to LDAR under the proposed regulation. Pneumatic devices are used for maintaining a process condition such as liquid level, pressure, pressure differential, and temperature at gas production facilities and will also be subject to LDAR and, in certain circumstances, replacement under the proposed regulation.

Figure 8: Diagram of a Typical Natural Gas Well



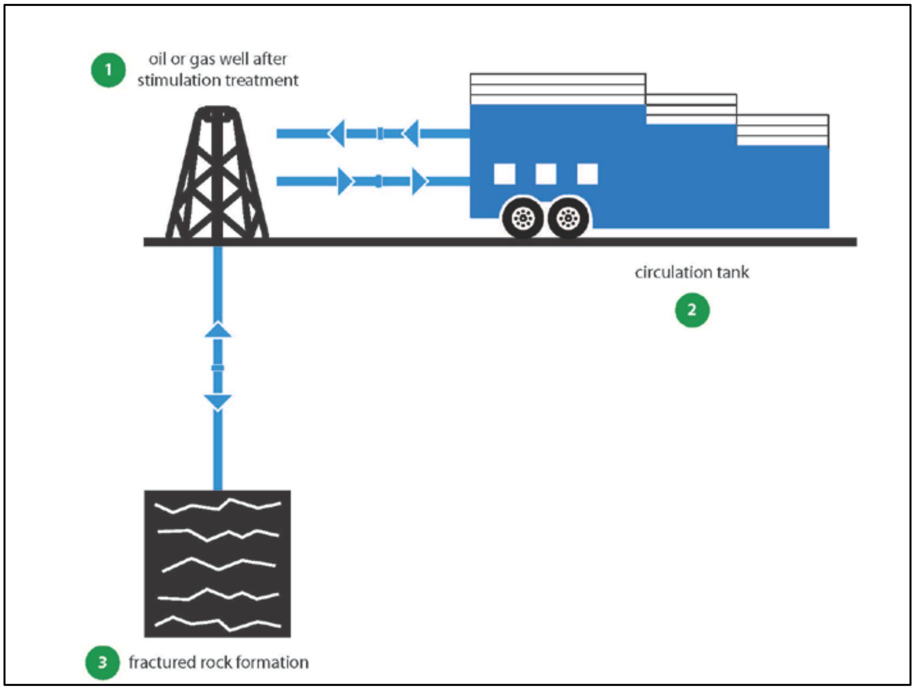
b) Liquids Unloading

Over time, dry gas wells accumulate liquids that can impede and sometimes halt gas production. When the accumulation of liquid results in the slowing or cessation of gas production, removal of fluids (e.g., liquids unloading) is required in order to maintain production. Gas flow is maintained by removing accumulated fluids, through the use of specialized equipment installed in the well such as velocity tubing or a plunger lift system, or with the use of remedial treatments such as swabbing, soaping, or by venting the well to atmospheric pressure (referred to as "blowing down" the well)[33]. The proposed regulation would require that vented natural gas from liquids unloading

[33] U. S. EPA. 2006. Installing Plunger Lift Systems in Gas Wells. Office of Air and Radiation: Natural Gas Star Program. Washington, DC.

be measured or calculated and reported, if the liquids unloading operation is not utilizing a 95% effective vapor collection system.

Figure 9: Diagram of a Circulation Tank for Well Stimulation Treatments



c) Crude Oil, Condensate, and Produced Water Separation and Storage

The purpose of the separation system is to process the emulsion into clean marketable products such as oil, natural gas, or condensates, while separating out water and other debris. For example, in crude oil production the separation system (6, 3) allows the emulsion to separate into associated gas, crude oil, and produced water. (6, 4) There are several types of separators that may be used, depending on the type of operations. They include pressure vessels, free water knockouts, gravity separators, and wash tanks.

The crude oil production separator allows for an initial separation that splits the stream into a gas component (associated gas), a liquid crude component, and a water component. This process is generally achieved through a series of vessels where associated gas is allowed to flash, or bubble out, and water to settle at the bottom, with oil taken out from the middle. Potentially large amounts of gas flash off at this point. Once the production separation has been completed, crude oil (6, 5) and associated gas are usually stored briefly onsite in order to stabilize flow between production wells and pipeline or trucking transportation sites. Produced water is either cleaned up and re-used for other purposes or stored for disposal. When stored at the production facility, crude oil, associated gas, and produced water are kept in storage tanks or sumps (produced water only). The proposed regulation establishes an emissions standard for the separator and tank systems, which includes the separator and first water and first oil tank. The water tank could be sump for produced water.

Separator and tank systems must conduct flash testing to determine emissions levels and if the results show the separator and tank system emissions are above 10 MT of methane per year, two provisions are triggered: (1) the system must employ a vapor collection system, capturing the fugitive emissions at the separator and first water and crude tank. (2) the system is subject to LDAR. Pressure vessels are subject to LDAR regardless of whether the standard is exceeded. More detail on vapor collection systems and LDAR is available in section II.C.1.-2. in this document.

Pneumatic devices and pumps are widespread throughout oil and natural gas operations, including in the separator and tank systems. At crude oil production facilities, pneumatics are generally operated using compressed air or electricity; however, high-pressure natural gas may be used to operate the devices. These devices are used to maintain a process condition such as liquid level, pressure, pressure differential, and temperature. Additionally, compressors and pneumatics are used to move associated gas from the separator system along to the gas pipeline.

Natural gas operated pneumatic devices and pumps will be subject to LDAR under the proposed regulation, and in certain circumstances, may warrant replacement. Compressors will also be subject to LDAR. Pneumatic devices and pumps not operated by natural gas are not subject to the proposed regulation.

d) Natural Gas Gathering and Boosting Stations

Gathering and boosting stations collect gas from multiple wells and move it toward the natural gas processing plant. Equipment and components at these facilities include compressors to increase the pressure of gas in the pipeline from the relatively low pressure coming from the production fields to medium pressure; pneumatic devices and pumps to maintain liquid levels, pressure, and temperature; and water knock out tanks that store water and condensate.

The proposed regulation establishes an emissions standard for compressors and a threshold for controls for any separator or storage tanks at gathering and boosting stations. If compressor flow rates are measured above the standard, in addition to any penalties, the compressor must be repaired, replaced, or the gas must be collected and routed to a vapor collection system in order to meet the standard.

In addition, compressors will be subject to LDAR. Separator and tank systems must conduct flash testing to determine emissions levels and if the results show the separator and tank system emissions are above 10 MT of methane per year, two provisions are triggered: (1) the system must employ a vapor collection system, capturing the fugitive emissions at the separator and first water and crude tank. (2) the system is subject to LDAR. Pressure vessels are subject to LDAR regardless of whether the standard is exceeded.

Natural gas operated pneumatic devices will be subject to LDAR and, in certain circumstances, may warrant replacement under the proposed regulation.

e) Natural Gas Processing Plants

Natural gas processing plants process raw natural gas and separate the various hydrocarbons and fluids from the raw natural gas, to produce what is known as "pipeline quality" dry natural gas. Natural gas used by consumers is composed almost entirely of methane. The raw natural gas commonly exists in mixtures with other hydrocarbons depending on the source of the natural gas (i.e. associated gas from crude oil production or dry gas) and reservoir characteristics, including: ethane, propane, butane, pentanes, the BTEX chemicals (benzene, toluene, ethylbenzene, and xylenes), water vapor, hydrogen sulfide (H_2S), carbon dioxide, helium, nitrogen, and other compounds. This process is analogous to the processing and refining of crude oil but less complicated.

The proposed regulation covers a subset of equipment at these facilities, focusing on large methane sources. The proposed regulation does include requirements for: compressors to move gas; pneumatic devices and pumps to maintain liquid levels, pressure, and temperature; and water knock out tanks that store water and condensate, and other components. The proposed regulation establishes an emissions standard for compressors and a threshold for controls for any separator or storage tanks at natural gas processing plants. If compressor flow rates are measured above the standard, in addition to any penalties, the compressor must be repaired, replaced, or the gas must be collected and routed to a vapor collection system in order to meet the standard. In addition, compressors will be subject to LDAR. Separator and tank systems must conduct flash testing to determine emissions levels and if the results show the separator and tank system emissions are above 10 MT of methane per year, two provisions are triggered: (1) the system must employ a vapor collection system, capturing the fugitive emissions at the separator and first water and crude tank. (2) the system is subject to LDAR. Pressure vessels are subject to LDAR regardless of whether the standard is exceeded. Natural gas-operated pneumatic devices will be subject to LDAR and, in certain circumstances, replacement under the proposed regulation. Other components are also subject to LDAR.

f) Natural Gas Transmission Compressor Stations

Natural gas-transmission compressor stations, function to move gas further down the pipeline by either increasing the pressure of gas in the pipeline from the medium pressure coming from the gathering and boosting stations to the high pressure of the transmission pipeline or maintaining the high pressure of the transmission pipeline when pipeline flow pressure decreases. Equipment at these facilities include: compressors to increase the pressure of gas; pneumatic devices and pumps to maintain liquid levels, pressure, and temperature; and water knock out tanks that store water and condensate. The proposed regulation establishes an emissions standard for compressors and a threshold for controls for any separator or storage tanks at natural gas transmission compressor stations. If compressor flow rates are measured above the standard, in addition to any penalties, the compressor must be repaired, replaced, or the gas must be collected and routed to a vapor collection system in order to meet the standard. In addition, compressors will be subject to LDAR. Separator and tank systems must conduct flash testing to determine emissions levels and if the results show the separator and tank system emissions are above 10 MT of methane per year, two provisions are triggered: (1) the system must employ a vapor collection system, capturing the fugitive emissions at the separator and first water and crude tank. (2) the system is subject to LDAR. Pressure vessels are subject to LDAR regardless of whether the standard is exceeded. Natural gas-operated pneumatic devices will be subject to LDAR and, in certain circumstances, replacement under the proposed regulation.

g) Natural Gas Underground Storage

Natural gas is most commonly stored underground under pressure in three types of facilities: depleted reservoirs in oil or natural gas fields, aquifers, and salt cavern formations. In 2014, California had 14 active natural gas underground storage sites and one undergoing decommissioning.[34] Most of the storage is used for system balancing and as a way to maintain steady and high-utilization of pipeline capacity. The remaining storage facilities are primarily used as depositaries for gas produced within the state that is not immediately

[34] U. S. EIA. 2015. Underground Natural Gas Storage Capacity. http://www.eia.gov/dnav/ng/ng_stor_cap_dcu_SCA_a.htm

marketable.[35] The wells located at these facilities may function in both a natural gas injection and withdrawal capacity. These wells may be newly constructed or repurposed oil or natural gas production wells. Additionally, abandoned or idle wells may be located at facilities where there was previous oil or natural gas production.

The proposed regulation would require that each underground storage facility be monitored to enable the early detection of well leaks and alert operators of potentially large releases of methane, like at the Aliso Canyon facility. This includes LDAR on components at the wellhead as well as continuous ambient air monitoring at the field. Storage facility monitoring requirements under the proposed regulation built upon the DOGGR's emergency regulation requirements and will replace that leak detection protocol once the plans are fully in place.

Additionally, equipment at these facilities covered under the proposed regulation include: (1) compressors to move gas; (2) pneumatic devices and pumps to maintain liquid levels, pressure, and temperature; and (3) water knock out tanks that store water and condensate. The proposed regulation establishes an emissions standard for compressors and a threshold for controls for any separator or storage tanks at natural gas transmission compressor stations. If compressor flow rates are measured above the standard, in addition to any penalties, the compressor must be repaired, replaced, or the gas must be collected and routed to a vapor collection system in order to meet the standard. In addition, compressors will be subject to LDAR. Separator and tank systems must conduct flash testing to determine emissions levels and if the results show the separator and tank system emissions are above 10 MT of methane per year, two provisions are triggered: (1) the system must employ a vapor collection system, capturing the fugitive emissions at the separator and first water and crude tank. (2) the system is subject to LDAR. Pressure vessels are subject to LDAR regardless of whether the standard is exceeded. Natural gas operated pneumatic devices will be subject to LDAR and, in certain circumstances, replacement under the proposed regulation.

C. PROPOSED SOLUTIONS TO THE PROBLEM – CONTROL MECHANISMS

This section describes the control mechanisms used by the proposed regulation and identifies components that may be part of the control mechanism that are covered under the proposed regulation. The table below serves as a summary of the control mechanisms used in each category, for quick reference.

[35] U. S. EIA. 2008. Underground Natural Gas Storage. https://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/undrgrnd_storage.html #western

Table 4: Control Mechanisms by Category

Category	Equipment	Threshold	Control Mechanism
Onshore and offshore crude oil or natural gas production	wellhead	-[2]	LDAR
	circulation tanks and liquids	-	vapor control; LDAR
	components	-	LDAR
	gathering system[1]	-	LDAR
	pressure vessel	-	LDAR
	reciprocating compressor	-	LDAR
	pneumatics	No bleed	LDAR; replacement
	liquids unloading	-	reporting
Crude oil, condensate, and produced water separation and storage	separator and tank system	>10 metric tonnes per year CH_4	vapor control; LDAR
	pneumatics	No bleed	LDAR; replacement
	reciprocating compressor	-	LDAR
	components	-	LDAR
Natural Gas Gathering and Boosting Stations	separator and tank system	>10 metric tonnes per year CH_4	vapor control; LDAR
	pneumatics	No bleed	LDAR; replacement
	reciprocating compressor	>2 scfm[3]	repair or replace; LDAR
	components	-	LDAR
Natural Gas Processing Plants	separator and tank system	>10 metric tonnes per year CH_4	vapor control; LDAR
	pneumatics	No bleed	LDAR; replacement
	reciprocating compressor	>2 scfm	repair or replace; LDAR
	components	-	LDAR
Natural Gas Transmission Compressor Stations	separator and tank system	>10 metric tonnes per year CH_4	vapor control; LDAR
	pneumatics	No bleed	LDAR; replacement
	reciprocating compressor	>2 scfm	repair or replace; LDAR
	centrifugal compressor	>3 scfm	vapor control; LDAR
	components	-	LDAR
Natural Gas Underground Storage	wellhead	-	LDAR and enhanced monitoring
	separator and tank system	>10 metric tonnes per year CH_4	vapor control; LDAR
	pneumatics	No bleed	LDAR; replacement
	reciprocating compressor	>2 scfm	repair or replace; LDAR
	components	-	LDAR and enhanced monitoring

1. e.g., piping, flow lines, gathering lines, or bulk header
2. "-" means that there is no threshold for the control mechanisms
3. standard cubic feet per minute

1. Vapor Collection System (VCS)

Vapor collection and recovery is the process of collecting the vapors entrained in produced water from crude oil production, or vapors from produced water from natural gas production, from tanks so they do not escape into the atmosphere. Recovered vapors are sent either to the sales gas or fuel gas system, injected underground, or flared/incinerated.

The proposed regulation specifies that collected vapors be required to go into an existing sales gas system, existing fuel gas system, or an existing underground injection well. If none of these systems is available, the vapors can go to an existing flare, provided it can still meet already permitted emission limits. In absence of existing systems, a new vapor control device is required and must meet the NO_x emission standard in the proposed regulation. This could include a low-NO_x[36] vapor control device or other non-destructive device[37]. In areas classified as in attainment with all state and federal ambient air quality standards, devices would not have to meet the NO_x emission standard.

Vapor collection systems include gathering lines, compressors, and pneumatic devices and pumps; the entire system will be subject to LDAR under the proposed regulation. In addition, the proposed regulation establishes an emissions standard for non-field compressors, which, if exceeded, in addition to any applicable penalties, require the compressor be repaired, replaced, or the gas must be collected and routed into the vapor collection system. Natural gas operated pneumatic devices will be subject to LDAR and, in certain circumstances, replacement under the proposed regulation.

2. Leak Detection and Repair

Leak detection and repair, or LDAR, describes the process of locating and repairing fugitive leaks, which are the unplanned losses of methane from pipes, flanges, seals, or through the moving parts of valves, pumps, compressors, and other types of equipment and components. The air districts within the major oil producing regions of the State have had LDAR programs, or Inspection and Maintenance (I&M) programs, for decades in order to reduce volatile organic compound (VOC) emissions. However, because of the focus on VOCs, current air district I&M programs do not cover components such as valves, flanges, seals, etc., that are primarily used in natural gas service. ARB staff estimates that of all of the components in the oil and gas sector, more than 80 percent are already covered by existing air district I&M programs to prevent the release of VOC emissions, whereas the

[36] A device that achieves 95 percent vapor control efficiency and does not generate more than 15 parts per million by volume NO_x when measured at 3% oxygen.
[37] A device that achieves 95 percent vapor control efficiency and does not result in emissions of nitrogen oxides (NO_x).

LDAR component of the proposed regulation is aimed at the remaining 20 percent of components.

In addition to requiring LDAR on the major equipment and components described in the previous section (i.e., compressors, pneumatics, storage tanks and separators), the proposed regulation will also require LDAR programs to include additional components. Some examples include:

- Valves used to either restrict or allow the movement of fluids,
- Connectors and fittings used to join piping and process equipment together,
- Sampling connections utilized to obtain samples from within a process, and
- Pressure relief devices designed to protect equipment from exceeding the maximum allowable working pressure.

The LDAR program will require the repair, retrofit, or replacement of leaking equipment and components and would require implementation of improved management practices for reducing vented emissions, such as keeping hatches, or other access point on storage tanks, closed and properly sealed during normal operation, or sealing open-ended lines and valves.

3. Equipment Replacement

The proposed regulation will require some equipment be replaced when it cannot be repaired to meet the established standards. For example, continuous bleed pneumatic devices[38] and pumps will likely be replaced with similar devices that meet the leak-free or no venting standard established in the proposed regulation. Existing intermittent pneumatic devices emitting below 6 scfh are exempt from this requirement.

In the event that additional vapors are collected and routed into an existing vapor control system operating a vapor control device (i.e., flare), the proposed regulation will require that the existing vapor control device be replaced with a new vapor control device, (unless the existing device is compliant with the low-NOx requirements of the proposed regulation). This could include a low-NO_x vapor control device or other non-destructive device, unless the area is classified as in attainment with all state or federal ambient air quality standards in which case any device that achieves a 95 percent vapor control efficiency of total emissions would be allowed.

[38] Continuous bleed controllers, used to modulate flow, liquid level, or pressure, for which gas is vented continuously.

D. SUMMARY OF ESTIMATED EMISSION BENEFITS

The proposed regulation is designed to reduce methane emissions from specified oil and gas facilities within California. The proposed regulation would result in slight CO_2 emission increases (i.e., combustion of collected vapors); however, these emissions would be in lieu of the release of methane into the atmosphere, which has a substantially higher global warming potential (GWP) than CO_2. Implementation of the proposed regulation would result in monitoring (e.g., inspections, repairs) and reporting, as well as collection and disposal of methane vapors associated with oil and gas facilities. ARB estimates statewide GHG emission benefits of approximately 1,523,000 metric tons of CO_2 equivalents per year.[39]

Table 5: Annual Methane Emissions and Reductions using the 20 and 100 year GWP

	Total annual emissions (MT CO_2e, **GWP=72)**	Annual reductions from proposed regulation (MT CO_2e, **GWP=72)**	Total annual emissions (MT CO_2e, **GWP=25)**	Annual reductions from proposed regulation (MT CO_2e, **GWP=25)**
Separators and tanks	566,000	538,000	197,000	187,000
LDAR	983,000	590,000	341,000	205,000
Pneumatics	319,000	319,000	111,000	111,000
Reciprocating compressors	504,000	68,000	175,000	24,000
Centrifugal compressors	3,700	3,500	1,300	1,200
Well stimulation circulation tanks	5,200	4,900	1,800	1,700
TOTAL from sources subject to controls in the proposed regulation	**2,381,000**	**1,523,000**	**827,000**	**529,000**
Other upstream oil and gas sources not subject to controls in the proposed regulation[40]	1,047,000	0	364,000	0
TOTAL	**3,428,000**	**1,523,000**	**1,191,000**	**529,000**

[39] Using the 20-yr global warming potential, 72, from the 2007, IPCC Fourth Assessment Report: Climate Change report, for methane. Climate Change 2007. Synthesis Report. IPCC Fourth Assessment Report: Climate Change 2007. http://www.ipcc.ch/pdf/assessment-report/ar4/syr/ar4_syr_full_report.pdf

[40] The proposed regulation covers a subset of emission sources within the oil and gas upstream sector. Although large in aggregate, these are generally smaller sources. Also includes remaining emissions from sources controlled by districts. For example tank measures are 95% effective so there are 5% of the original emissions remaining.

In addition to the GHG benefits, ARB estimates that the controls and associated compliance responses from the proposed regulation will also provide substantial statewide reductions of several toxic air contaminants and criteria air pollutants, including hydrocarbons, VOC's, and the BTEX suite of chemicals. ARB also estimated the net NO_x emissions impact of the proposed regulation. This analysis is described in detail in Appendix C: Environmental Analysis. The leak detection and repair requirements will result in minor increases in vehicle emissions; however, these are offset statewide by NO_x reductions the proposed regulation is achieving through increased use of low- NO_x vapor control devices. While ARB estimates an essentially neutral impact on NOx statewide, in the San Joaquin Valley ARB estimates a NO_x benefit of 0.46 tons/year compared to current conditions.

Table 6: Statewide Non-GHG Air Emission Benefits

Category	Total Hydrocarbons	VOCs	Benzene	Toluene	Ethyl-Benzene	Xylenes	NOx
TOTAL non-GHG benefits from proposed regulation (tons/year)	27,837	3,627	62	29	4.6	23	(<0.1)

E. SUMMARY AND RATIONALE FOR EACH REGULATORY PROVISION

In this chapter, ARB Staff provides a brief summary of the provisions included in the proposed regulation, explaining the rationale for each requirement.

1. Section 95665. Purpose and Scope.

Summary of Section 95665

This section states that the purpose of the regulation is to establish GHG emission standards for crude oil and natural gas facilities and that the regulation has been designed to serve the purpose of the California Global Warming Solutions Act as codified in Section 38500-38599 of the California Health and Safety Code.

Rationale for Section 95665

This section establishes that the proposed regulation will reduce GHG emissions at crude oil and natural gas facilities and provide reference under applicable ARB authority. The purpose of the proposed regulation is to set emissions standards and establish requirements to control fugitive and vented GHG emissions from oil and gas facilities. Controlled emissions are composed primarily of methane. Methane is a powerful GHG with a GWP 72 times that of carbon dioxide (on a 20-year timeframe), and is found in significant quantities at oil and gas facilities.

2. Section 95666. Applicability.

Summary of Section 95666

This section specifies the types of crude oil and natural gas facilities covered by the proposed regulation. The affected facilities include (1) Onshore and offshore crude oil or natural gas production facilities; (2) Crude oil and produced water separation and storage facilities; (3) Natural gas underground storage facilities; (4) Natural gas gathering and boosting stations; (5) Natural gas processing plants; and (6) Natural gas transmission compressor stations. The section specifies that owners and operators of these facilities must ensure that their facilities, equipment, and components are in compliance with the requirements of the proposed regulation at all times, and are jointly and severally liable for doing so.

Rationale for Section 95666

This section ensures that the proposed regulation will apply to all new and existing oil and gas facilities located within California and California waters, regardless of emissions level. This section also clarifies that owners and operators are jointly and severally liable if they do not comply, and that they must maintain compliance continuously, which is necessary to ensure compliance with the regulations.

3. Section 95667. Definitions.

Summary of Section 95667

This section establishes definitions for the terms used in the proposed regulation. Establishing definitions for key terms provides clarity and specificity in the proposed regulation.

Rationale for Section 95667

It is necessary that ARB define its terms as they apply to the proposed regulation.

4. Section 95668. Standards.

Summary of Section 95668

This section specifies that the standards apply to all facilities listed in section 95666, and that exemptions to one standard do not provide an exemption to other required standards.

Rationale for Section 95668

This section is necessary to clarify that the standards in this section apply to all listed facilities, and to make clear that any available exemptions apply narrowly, and do not compromise emission reductions required by other applicable standards.

5. Section 95668(a). Separator and Tank Systems.

Summary of Section 95668 (a)(1)

This section indicates that the flash analysis testing and vapor collection system requirements in the following section apply to separator and tank systems located at facilities listed in section 95666.

Rationale for Section 95668 (a)(1)

This section is necessary to define the types of equipment systems to which the section applies.

Summary of Section 95668 (a)(2)(A)

This section specifies that separator and tank systems that receive less than 50 barrels of crude oil and less than 200 barrels of produced water per day are exempt from the requirements of this section.

Rationale for Section 95668 (a)(2)(A)

Methane is emitted from the production of crude oil, condensate, and produced water when the fluids are produced from an underground reservoir and separated or stored on the surface. The emissions are primarily a result of depressurizing the liquids from reservoir pressure to a lower surface pressure and subjecting the liquids to changes in temperature. The analysis showed that separator and tank systems with a production level of than 50 barrels of crude oil per day and less than 200 barrels of produced water do not produce enough liquids to meet the proposed emissions standard and therefore do not warrant flash emissions testing, or a permanent vapor collection system. For more information, see Appendix D.

Summary of Section 95668 (a)(2)(B)

This section specifies that the requirements of this section do not apply to separator and tank systems that are already controlled with the use of a vapor collection system.

Rationale for Section 95668 (a)(2)(B)

Separator and tank systems that are controlled with a vapor collection system in accordance with local air district requirements are already in compliance with this regulation.

Summary of Section 95668 (a)(2)(C)

This section specifies that the requirements of this section do not apply to separators, tanks, and sumps that have not contained crude oil, condensate or produced water for at least 30 calendar days.

Rationale for Section 95668 (a)(2)(C)

Staff's analysis shows that separators, tanks, and sumps that have not contained crude oil, condensate, or produced water for at least 30 calendar days do not contain sufficient quantities of natural gas to warrant emissions control.

Summary of Section 95668 (a)(2)(D)

This section specifies that the requirements of this section do not apply to tanks used for temporarily separating, storing, or holding emulsion, crude oil, condensate, or produced water from a newly constructed well for up to 90 calendar days following initial production from that well, provided the tank is not used to circulate liquids from a well that has undergone well stimulation.

Rationale for Section 95668 (a)(2)(D)

This exemption is necessary to provide a regulated party with the necessary time required to complete the construction of a newly drilled well using temporary tanks to store drilling fluids, emulsion, or other liquids prior to diverting production liquids into a separator and tank system. During this time period, an owner or operator will evaluate a number of characteristics, including well production rate and annual methane emissions from the produced liquids. If the annual methane emission rate is above the specified standard, the information can be used to design and construct an appropriate vapor collection system.

Summary of Section 95668 (a)(2)(E)

This section specifies that the requirements of this section do not apply to tanks used for temporarily separating, storing, or holding emulsion, crude oil, condensate, or produced water from wells undergoing rework or inspection, for up to 90 calendar days following completion, provided the tank is not used to circulate liquids from a well that has undergone well stimulation.

Rationale for Section 95668 (a)(2)(E)

This exception is necessary to inform a regulated party that tanks used in conjunction with temporary well rework and inspection are not subject to the proposed regulation requirements. These tanks are used to hold small amounts of liquids that are expelled from a well while removing or replacing tubing or flushing small quantities of liquids from the well bore. Because the tanks are neither used in a production capacity nor used in conjunction with a well stimulation treatment, they do not warrant flash emissions testing or a permanent vapor collection system.

Summary of Section 95668 (a)(2)(F)

This section specifies that the requirements of this section do not apply to tanks that recover less than 10 gallons per day of any petroleum product from equipment, provided that the owner or operator maintains a list of the amount of liquid recovered.

Rationale for Section 95668 (a)(2)(F)

This exemption is necessary to specify that tanks used to store small quantities of waste fluids from equipment are different from tanks used in crude oil and natural gas production. These tanks are often used to clean out liquid knockout traps from large compressors or equipment but are not used in the production of crude oil or natural gas. A maximum throughput limit is specified as well as daily record keeping requirements to ensure that the tanks are used within the parameters specified.

Summary of Section 95668(a)(3)

This section specifies that existing separator and tank systems not already controlled with a vapor collection system must conduct flash analysis testing of the crude oil, condensate, or produced water processed, stored, or held in the system by the effective date.

Rationale for Section 95668(a)(3)

This section ensures that, beginning on the effective date, existing separators and tank systems are controlled with a vapor collection system.

Summary of Section 95668(a)(4)

This section specifies that new separator and tank systems not already controlled with a vapor collection system must conduct flash analysis testing of the crude oil, condensate, or produced water processed, stored, or held in the system within 90 days of system startup.

Rationale for Section 95668(a)(4)

This section ensures that, beginning on the effective date, new separator and tank systems have 90 days from initial startup, to conduct flash analysis testing and reporting, which is used to determine if the new separator and tank system is above the proposed methane emissions standard and requires the installation of a vapor collection system.

Summary of Section 95668(a)(5)(A)

This section specifies that flash analysis testing must be conducted in accordance with the ARB Test Procedure for Determining Annual Flash Emission Rate of Methane from Crude Oil, Condensate, and Produced Water as described in Appendix C to the regulation.

Rationale for Section 95668(a)(5)(A)

This section ensures that the approved method flash analysis testing will be followed by every regulated party.

Summary of Section 95668(a)(5)(B)

This section specifies that that no crude oil, condensate, or produced water may be diverted through a gauge tank that is open to the atmosphere and located upstream of the separation and system while testing is conducted.

Rationale for Section 95668(a)(5)(B)

This requirement is necessary to ensure that all flash analysis testing is facilitated in the same manner, preventing potential testing bias in facilities that might otherwise allow the products to be open to the atmosphere, before the point at which flash testing takes place.

Summary of Section 95668(a)(5)(C-D)

These sections specify that the owner or operator use the flash analysis test results provided by the laboratory to calculate the annual methane emissions for the crude oil, condensate, and produced water, adding the emissions together.

Rationale for Section 95668(a)(5)(C-D)

These requirements are necessary to ensure that each facility owner or operator is calculating the emissions and adding them together, in a consistent manner across all facilities in the state.

Summary of Section 95668(a)(5)(E-F)

These sections require that owners or operators maintain a record of flash analysis testing and report the results to ARB, per sections 95671 and 95672, respectively. Additionally, it provides for ARB to request further information or testing, if it is determined that test results are not representative of similar systems or wells.

Rationale for Section 95668(a)(5)(E-F)

These sections are necessary to provide recordkeeping requirements for flash analysis tests at a particular location or facility. Additionally, it gives ARB the ability to inquire about atypical flash analysis test results.

Summary of Section 95668(a)(6)

This section specifies that by the effective date, owners or operators of a separator and tank system with an annual emission rate greater than or equal to 10 metric tons per year of methane must control the emissions from the system as well as uncontrolled gauge tanks upstream, with a vapor collection system as specified in section 95668.

Rationale for Section 95668(a)(6)

This section is necessary to inform a regulated party with a separation and tank system with an annual emission rate greater than 10 metric tons per year of methane that the system and all uncontrolled upstream gauge tanks are subject to the vapor collection system requirement. This requirement is necessary to ensure the separator and tank system is controlled as intended and tested while accounting for uncontrolled upstream gauge tanks that have the potential to vent emissions prior to the separator and tank system.

Summary of Section 95668(a)(7)

This section specifies that new separator and tank systems installed after January 1, 2018 with emissions that exceed the proposed regulation standard must be controlled with the use of a vapor collection system within 180 days from the date that flash analysis testing was conducted.

Rationale of Section 95668(a)(7)

This section is necessary to specify the proposed timeframe for controlling emissions from new separator and tank systems that exceed the proposed regulation standard. The proposed timeframe is intended to provide a regulated party with time necessary to design and construct a system as well as obtain the necessary local air district permits.

Summary of Section 95668(a)(8)

This section specifies that a regulated party with a separator and tank system with methane emissions measured below the proposed standard must conduct annual flash emissions testing for at least three years. If the results of three consecutive years of testing are below 10 metric tons of methane per year, the annual testing requirement may be reduced to once every five years.

Rationale for Section 95668(a)(8)

This requirement ensures that the results of flash analysis testing are accurate and then eliminates the need to conduct repetitive testing. Due to fluctuations in the liquids produced from a well or group of wells, methane emissions from each system may change slightly throughout the year. This is usually due to changes in the amount of oil or water produced. In order to provide a consistent emission baseline for each system, and to avoid the need for testing each time the system fluctuates, staff is proposing an annual testing requirement. The proposed testing requirement may be reduced to once every five years if previous results show that the emissions are consistently below the proposed standard.

Summary of Section 95668(a)(8)(A)

This section requires that the annual methane emissions must be recalculated if the crude oil, condensate, or produced water throughput increases by more than 20 percent per calendar year, after the third consecutive year of testing.

Rationale for Section 95668(a)(8)(A)

Due to the variability of fluids produced from a well or group of wells, this requirement is necessary to determine the annual methane emissions from a well with increased throughput. Methane emissions are directly related to the production rate of liquids, so an increase in the production of liquids will affect the annual methane emissions. To address daily fluctuations in volume with constant liquid composition, staff proposes that annual emissions be recalculated if there is an increase in production of crude oil, condensate, or produced water by more 20 percent per calendar year. The new methane emission rate is to be recalculated using the gas composition analysis provided during the previous year of testing along with the new volume of liquid. This will ensure that each facility maintains a current record of methane emissions for separator and tank systems while eliminating the need for extra testing.

Summary of Section 95668(a)(8)(B)

This section requires that owners or operators required to recalculate emissions with prior flash analysis testing, keep a record of the recalculations as specified. Additionally, it provides for ARB to request further information or testing, if it is determined that test results are not representative of similar systems or wells.

Rationale for Section 95668(a)(8)(B)

This section is necessary to provide recordkeeping requirements for emissions recalculation using prior flash analysis tests at a particular location or facility. Additionally, it gives ARB the ability to inquire about non-typical flash analysis test results

6. Section 95668(b). Circulation Tanks for Well Stimulation Treatments.

Summary of Section 95668(b)(1)

This section requires owners or operators of circulation tanks used in conjunction with well stimulation treatments to submit a best practices management plan designed to reduce methane emissions from circulation tanks, by the effective date listed in the regulation. Additionally, ARB's Executive Officer may approve or disapprove the plan, in whole or in part.

Rationale for Section 95668(b)(1)

This section is necessary to inform a regulated party that uses circulation tanks that they must submit a best practices management plan to ARB by the effective date specified. This requirement is necessary to ensure that a regulated party operates the uncontrolled tanks using the best practices that are available to limit the volume of emissions from the tanks while emission control equipment is designed and tested. Some best management practices that are available include using minimal amounts of water necessary to remove sand from a wellbore and minimizing the duration of circulation activity. All best practices management plans require ARB Executive Officer approval and may require modification prior to final approval, which is necessary to ensure that the plans achieve their intended purpose.

Summary of Section 95668(b)(2) and (b)(2)(A)

This section requires facilities that use circulation tanks in conjunction with well stimulation treatments to submit a written report to ARB that details the results of a technical evaluation of equipment used to control emissions from circulation tanks. The report must be provided, in writing, to ARB's Executive Officer by the effective date. The report must include testing results conducted by the owner or operator or equipment manufacturers.

Rationale for Section 95668(b)(2) and (b)(2)(A)

This section is required to inform a regulated party that uses circulation tanks that they must perform emissions testing of vapor control equipment used on a circulation tank and submit a written report of the results to ARB by the effective date specified. This requirement is necessary to provide a regulated party with time to work with circulation tank and vapor collection system equipment manufacturers to design and test emission control equipment. Examples of equipment that may be used to control emissions include a portable gas separator and a portable low-NOx incinerator to combust the collected vapors. We encourage owners or operators as well as equipment manufacturers to work with ARB during the development of the technical demonstration.

Summary of Section 95668(b)(3)

This section requires that all owners and operators of facilities that use circulation tanks during well stimulation treatments must control the methane emission with 95 percent control efficiency.

Rationale for Section 95668(b)(3)

This section is required to inform a regulated party that circulation tanks used in conjunction with well stimulation treatments by the effective date specified. This requirement is necessary to provide a regulated party with time to purchase and install vapor control equipment following the results of a successful technical demonstration specified in section 95668(b)(2).

7. Section 95668(c). Vapor Collection Systems and Vapor Control Devices.

Summary of Section 95668(c)(1)

This section specifies the types of equipment subject to the vapor collection system and control device requirements and the effective date on which the requirements apply.

Rationale for Section 95668(c)(1)

This requirement is necessary to define the types of equipment subject to the vapor collection system and control requirements and the date on which the requirements apply.

Summary of Section 95668(c)(2)

This section specifies that the vapor collection system must direct the collected vapors to one of following: (A) Existing sales gas system, (B) Existing fuel gas system, or (C) Existing gas disposal well.

Rationale for Section 95668(c)(2)

This section is required to ensure that any newly collected vapors are controlled using equipment that is already available at the facility and to minimize or eliminate ambient air quality impacts. Staff's analysis show that some oil and gas facilities have at least one of these options currently available, minimizing the cost of controlling emissions and preventing the need to install additional combustion equipment[41].

[41] ARB. 2013. Oil and Gas Survey. ARB 2007 Oil and Gas Industry Survey Results, Final Report, revised in October 2013.

Summary of Section 95668(c)(3)

This section specifies that if no existing sales gas system, fuel gas system, or gas disposal well is available to accept newly collected vapors, the regulated party must install a new vapor control device. New and replacement devices must meet the proposed regulation standards.

Rationale for Section 95668(c)(3)

This section is necessary to complement, and avoid interfering with, ambient air quality standards by ensuring that the installation of new combustion equipment used to reduce methane emissions avoids criteria pollutant or toxic impacts.

Summary of Section 95668(c)(3)(A)

This section specifies that a regulated party must install a new vapor control device to control newly collected vapors in the event that there is no existing vapor control device already installed at the facility.

Rationale for Section 95668(c)(3)(A)

This requirement is necessary to clarify that any existing facility without a vapor control device must install a new vapor control device in order to control the newly collected methane vapors. This alternative is only available when no existing sales gas system, fuel gas system, or underground injection well is available, and when no existing vapor control device is installed at the facility. This section is necessary to comply with the intent of the proposed regulation to control emissions of methane.

Summary of Section 95668(c)(3)(B)

This section specifies that if an existing device does not meet the standard in section 95668(c)(4), the regulated party currently operating an existing vapor control device that is subject to the proposed vapor collection system requirement must replace that existing vapor control device with a new vapor control device that meets the proposed regulation standards.

Rationale for Section 95668(c)(3)(B)

This requirement is necessary to ensure that any incremental increase in combusted methane vapors does not result in an increase of emissions that may affect attainment or local ambient air quality standards. If the existing device does not meet the standard, this alternative must be used when no existing sales gas system, fuel gas system, or gas disposal well is available, and when the facility currently operates an existing vapor control device. This section is necessary to comply with the intent of the proposed regulation to control emissions of methane without impacting local air quality.

Summary of Section 95668(c)(4)(A)

This section specifies that if a new vapor control device is to be installed in an area classified as in attainment with state or federal ambient air quality standards, the device must achieve at least 95% control efficiency and meet all applicable federal, state, and local air district requirements.

Rationale for Section 95668(c)(4)(A)

This section allows a regulated party to install any type of vapor control device that meets the specified control efficiency in a region classified as in attainment with ambient air quality standards, as long as it meets all applicable requirements. This section ensures emission controls required by the proposed regulation complements, and avoids interfering with applicable requirements for air quality.

Summary of Section 95668(c)(4)(B)

This section specifies that if a new vapor control device is to be installed in an area classified as non-attainment with state or federal ambient air quality standards the device must meet certain requirements. This requirement provides flexibility by clarifying that more than one type of vapor control device can fulfill the requirement.

Rationale for Section 95668(c)(4)(B)

This requirement is necessary to ensure that any incremental increase in combusted methane vapors does not result in an increase of emissions that may affect attainment or local ambient air quality standards.

Summary of Section 95668(c)(4)(B)1

This section specifies that a non-destructive vapor control device may be installed in an area classified as non-attainment with ambient air quality standards provided the device is at least 95% efficient in controlling emissions of methane and does not result in emissions of NO_x.

Rationale for Section 95668(c)(4)(B)1

Non-destructive control devices process collected vapors without a need for combustion. An example of such a device chills vapors to an extremely cold temperature which to turn converts the gas into liquid. The liquid may be used on-site or sold as a useable product. Although the technology is not currently employed within the oil and gas sector, manufacturers of the equipment are aware of a need for a system that can be used in this application, and ARB staff believes that the technology can be adapted for use in the oil and gas sector. This requirement is necessary to provide flexibility in the event that the technology becomes available for future oil and gas applications.

Summary of Section 95668(c)(4)(B)2

This section specifies that a vapor control device may be installed in an area classified as non-attainment with ambient air quality standards provided it is at least 95% efficient in controlling emissions of methane and does not generate more than 15 parts per million volume of NO_x when measured at 3% oxygen and does not require the use of supplemental fuel gas, other than gas required for a pilot burner, to operate.

Rationale for Section 95668(c)(4)(B)2

This section is necessary to ensure that newly collected vapors are controlled in areas classified as non-attainment with state or federal ambient air quality standards using a device that minimizes or reduces ambient air quality impacts. Examples of such devices that can be used to meet the proposed standards include low-NOx incinerators and microturbines. Low-NOx incinerators use proprietary technology to efficiently burn, and otherwise destroy, all of the collected vapors. Microturbines are used to generate electricity and create a beneficial use for waste gas, which is otherwise destroyed. This requirement is necessary to provide an emissions standard that reduces emissions affecting ambient air quality while controlling newly collected vapors and allowing the regulated party to continue oil and gas production.

Summary of Section 95668(c)(5)

This section specifies that if any newly collected vapors cannot be controlled using any of the alternative options specified in section 95668(c), then any equipment subject to the proposed regulation vapor collection system requirements must be removed from service by the date specified.

Rationale of Section 95668(c)(5)

This section is necessary to inform a regulated party that they cannot operate equipment that does not meet the proposed regulation vapor collection system requirements after the effective date specified in the proposed regulation. This requirement is necessary to comply with the intent of the proposed regulation to control emissions of methane in a manner that is consistent with state and federal ambient air quality standards.

Summary of Section 95668(c)(6)

This section specifies that vapor collection systems and control devices are allowed to be out of service for a certain number of calendar days each year for maintenance or utility power outages. Additionally, there is flexibility when replacing compliant devices, and during power outages.

Rationale of Section 95668(c)(6)

This section is required to provide a regulated party with a set amount of time, to take the vapor collection systems and control devices out of service, or to use an alternative method, to perform scheduled maintenance and to make an allowance for utility power outages.

8. Section 95668(d). Reciprocating Natural Gas Compressors.

Summary of Section 95668(d)(1)

This section specifies that reciprocating natural gas compressors used at crude oil and natural gas production facilities must comply with the proposed regulation standards.

Rationale of Section 95668(d)(1)

This section is necessary to inform a regulated party that reciprocating natural gas compressors located at the facilities listed are subject to the proposed regulation standards.

Summary of Section 95668(d)(2)

This section specifies that reciprocating compressors that operate less than 200 hours per year are exempt from the requirements of 95668(d), provided that the owner or operator keep a written record of operating hours, and can demonstrate it to ARB's Executive Officer, upon request.

Rationale of Section 95668(d)(2)

This exemption is necessary to prevent the unnecessary startup and running of a compressor in order to perform annual emissions testing. The unnecessary generation of emissions to perform emissions measurements conflicts with the proposed intent of the regulation to reduce annual methane emissions.

Summary of Sections 95668(d)(3)(A-B)

These sections are necessary to specify that components on the compressor must be tested and repaired during each inspection period according to the proposed LDAR requirements. Additionally, the rod packing or seal must also be tested in accordance with the proposed LDAR test procedure.

Rationale of Sections 95668(d)(3)(A-B)

These sections are necessary to inform a regulated party that regular emissions monitoring is required for the rod packing or seal in addition to other engine and compressor components.

Summary of Section 95668(d)(3)(C-D)

This section specifies that, by the effective date, compressor vent stacks used to vent rod packing or seal emissions shall either be controlled with the use of a vapor collection system as specified in section 95688(c) or shall be subject to measurement and, if above the minimum threshold in 95669, repaired within 30 days of the initial emissions flow rate measurement.

Rationale of Section 95668(d)(3)(C-D)

This section is necessary to specify that owners or operators have the option to control rod packing or seal emissions with the use of a vapor collection system. This section is also necessary to specify that compressors that control the rod packing or seal vent gas with the use of a vapor collection system are not required to conduct LDAR testing of the rod packing or seal. This section is also necessary to specify the repair timeframe for a rod packing or seal, which is different from other repair timeframes listed in LDAR. Due to the complexity of repairing these components, additional time is provided to allow the owner or operator to take the compressor out of service, order parts, and make all of the necessary repairs.

Summary of Section 95668(d)(3)(E)

This section specifies that the owner or operator of the reciprocating compressor shall maintain a record of rod packing leak concentration measurements that are measured above the minimum leak threshold as specified in Appendix A, Table 5. The owner or operator must also report a record of the measurements to ARB once per calendar year as specified in section 95672.

Rationale of Section 95668(d)(3)(E)

This requirement is necessary for an owner or operator to demonstrate to the ARB Executive Officer that emissions testing was conducted as specified in the proposed regulation and for ARB to maintain accurate records of emissions from these components.

Summary of Section 95668(d)(3)(F)

This section specifies that any compressor, which has been approved as a critical component, must be repaired by the end of the next process shutdown or within 12 months from the date of the initial flow rate measurement, whichever is sooner.

Rationale of Section 95668(d)(3)(F)

This section is necessary to prevent the shutdown of a critical process unit that has the potential to emit more emissions of methane than those from the defective component. Critical components are allowed additional time to make repairs, but must be repaired during the next process unit shutdown or within 12 months from the date of the initial leak concentration measurement, whichever is sooner. All critical components must be pre-approved by the ARB Executive Officer to receive this special designation.

Summary of Section 95668(d)(4)

This section applies to reciprocating natural gas compressors at natural gas gathering and boosting stations, processing plants, transmission compressor stations, and underground natural gas storage facilities listed in section 95666 and which are not covered under section 95668(d)(3).

Rationale of Section 95668(d)(4)

This section is necessary to differentiate between compressors located at the facilities listed which are subject to different rod packing or seal testing requirements and emissions than compressors located at production facilities.

Summary of Section 95668(d)(4)(A)

This section specifies that components on driver engines and compressors shall comply with the leak detection and repair requirements specified in section 95669.

Rationale of Section 95668(d)(4)(A)

This section is necessary to inform a regulated party that components on driver engines and compressors are subject to the LDAR testing requirements during each leak inspection.

Summary of Section 95668(d)(4)(B)

This section directs owners or operators of facilities to measure the rod packing or seal flow rate annually, and in compliance with the regulation, using one of the following methods: (1) Vent stacks must be equipped with a meter or instrumentation to measure the rod packing or seal emissions flow rate; or (2) Vent stacks must be equipped with a clearly identified access port installed at a height of no more than six (6) feet above ground level or a permanent support surface for making individual or combined rod packing or seal emission flow rate measurements

Rationale of Section 95668(d)(4)(B)

This section is necessary to inform a regulated party that regular rod packing or seal emission testing is required to comply with the proposed regulation, in the event that the vent stack emissions are not controlled with the use of a vapor collection system. The rod packing or seal must be measured annually using an emissions flow rate instrument. This measurement frequency was chosen because normal wear and tear on these compressors is low, and methods to measure the emissions rate are complex. In most applications, reciprocating compressors installed at the facilities specified are used to compress processed natural gas that is relatively free of contaminants that might wear out the rod packing or seal quickly. To provide flexibility with testing, owner or operator may use instrumentation, installed within the vent stack, to continuously measure the emissions flow rate or install an access port in the stack for making annual measurements.

Summary of Section 95668(d)(4)(C-E)

These sections specify that compressor vent stacks must either be controlled with the use of a vapor collection system or the rod packing must be measured annually, and any compressor with a rod packing or seal that exceeds 2 scfm (or 2 scfm times the number of rod packing cylinders), must be repaired within 30 calendar days from the date of the initial flowrate measurement. Additionally, the owner or operator must maintain a record of the flow rate measurements as specified in Appendix A, Table 7 of the proposed regulation and report the measurement result to ARB once per year.

Rationale of Section 95668(d)(4)(C-E)

These sections are necessary to specify that emissions from a rod packing or seal must either be controlled with the use of a vapor collection system or tested annually and repaired within 30 calendar days from the date of the initial flowrate measurement. These sections provide flexibility, giving an operator or operator the option to either control the emissions or perform annual measurements and make repairs as specified. The 30 calendar day repair timeframe provides time for a regulated party to take a compressor out of service, order parts, and make any necessary repairs.

Summary of Section 95668(d)(4)(F)

This section specifies that any compressor, which has been approved as a critical component by the ARB Executive Officer, must be repaired by the end of the next process unit shutdown or within 12 months from the date of the initial flow rate measurement, whichever is sooner.

Rationale of Section 95668(d)(4)(F)

This section is necessary to prevent the shutdown of a critical process unit that has the potential to emit more emissions of methane than those from the defective component. Critical components are allowed additional time to make repairs, but must be repaired during the next process unit shutdown or within 12 months from the date of the initial flow rate measurement, whichever is sooner. All critical components must be pre-approved by ARB to receive this special designation

9. Section 95668(e). Centrifugal Natural Gas.

Summary of Section 95668(e)(1)

With the exception of compressors listed in section 95668(e)(2), this section specifies that centrifugal natural gas compressors must comply with the proposed standards beginning on the date specified.

Rationale of Section 95668(e)(1)

This section is necessary to inform a regulated party that centrifugal natural gas compressors located at the facilities specified are subject to the proposed regulation requirements.

Summary of Section 95668(e)(2)

This section specifies that any centrifugal natural gas powered compressor operating less than 200 hours per calendar year is exempt from this section of the proposed regulation, provided that the owner or operator maintains a record of the operating hours per calendar year, and can provide them to ARB's Executive Officer, upon request.

Rationale of Section 95668(e)(2)

This exemption is necessary to prevent the unnecessary startup and running of a compressor in order to perform annual emissions testing. The unnecessary generation of emissions to perform emissions measurements conflicts with the proposed intent of the regulation to reduce annual methane emissions.

Summary of Sections 95668(e)(3)

This section specifies that centrifugal natural gas compressors that use wet seals or dry seals are subject to the proposed LDAR requirements.

Rationale of Sections 95668(e)(3)

This section is necessary to inform a regulated party that regular emissions testing is required for all components found on centrifugal natural gas compressors that use either a wet seal or dry seal system.

Summary of Sections 95668(e)(4)

This section specifies that centrifugal natural gas compressors with wet seals must be measured annually using one of the following methods: (A) Vent stacks shall be equipped with a meter or instrumentation to measure the wet seal emissions flow rate; or, (B) Vent stacks shall be equipped with a clearly identified access port installed at a height of no more than six (6) feet above ground level or a permanent support surface for making wet seal emission flow rate measurements.

Rationale of Sections 95668(e)(4)

This section is necessary to specify that wet seals must be measured annually to determine compliance with the proposed emission flow rate standard. This measurement frequency was chosen because normal wear and tear on these compressors is low and methods used to measure the emissions flow rate are complex. In most applications, centrifugal natural gas compressors are used to compress processed natural gas that is relatively free of contaminants that might wear out the wet seal quickly. To provide flexibility with testing, owner or operator may use instrumentation installed within the vent stack to continuously measure the emissions flow rate or install an access port in the vent stack for making annual flow rate measurements.

Summary of Section 95668(e)(5-7)

These sections specify that wet seal emissions that exceed 3 scfm (or 3 scfm times the number of seals) must either be controlled with the use of a vapor collection system or repaired within 30 calendar days from the date of the initial flowrate measurement. Additionally, the owner or operator must maintain a record of flow rate measurements as specified in Appendix A, Table 7 of the proposed regulation and report flowrate measurement results to ARB once per year.

Rationale of Section 95668(e)(5-7)

These sections are necessary to specify that owners or operators of compressors with wet seals must either control the emissions with the use of a vapor collection system or perform annual measurements and make repairs to wet seals that are measured above the flow rate standard. These sections provide flexibility, giving an operator or operator the option to either control wet seal emissions or perform annual measurements and make repairs as specified. The 30 calendar day repair timeframe provides time for a regulated party to take a compressor out of service, order parts, and make any necessary repairs. This also provides additional time to evaluate the possibility of controlling the wet seals with the use of a vapor collection system.

Summary of Section 95668(e)(8)

This section specifies that the owner or operator of any centrifugal compressor must maintain a record of the flow rate measurements as described in Appendix A, Table 7 of the proposed regulation and report it to ARB once per year.

Rationale of Section 95668(e)(8)

This requirement is necessary for an owner or operator to demonstrate to the ARB Executive Officer that emissions testing has been conducted as specified in the proposed regulation and for ARB to maintain accurate records of emissions from these components.

Summary of Section 95668(e)(9)

This section specifies that any compressor approved as a critical component must be successfully repaired by the end of the next process unit shutdown or within 12 months of the date of the initial flow rate measurement, whichever is sooner.

Rationale of Section 95668(e)(9)

This section is necessary to prevent the shutdown of a critical process unit that has the potential to emit more emissions of methane than those from the defective component. Critical components are allowed additional time to make repairs, but must be repaired during the next process unit shutdown or within 12 months from the date of the initial flow rate measurement, whichever is sooner. All critical components must be pre-approved by the ARB Executive Officer to receive this special designation.

10. Section 95668(f). Natural Gas Powered Pneumatic Devices and Pumps.

Summary of Section 95668(f)(1)

This section specifies that natural gas powered pneumatic devices and pneumatic pumps are subject to the proposed regulation standards.

Rationale of Section 95668(f)(1)

This section is necessary to inform a regulated party that both natural gas powered pneumatic devices and natural gas powered pneumatic pumps are subject to the proposed regulation.

Summary of Section 95668(f)(2)

This section specifies that continuous bleed pneumatic devices shall not vent natural gas after the effective date specified and must comply with the leak detection and repair standards..

Rationale of Section 95668(f)(2)

This requirement is necessary to prevent the venting of methane from continuous bleed pneumatic devices. By design, continuous bleed devices continuously vent natural gas into the atmosphere. Other types of non-venting pneumatic devices are available and continuous bleed devices may also be retrofitted to use compressed air or electricity to eliminate the vented emissions.

Summary of Section 95668(f)(2)(A)1-5

These sections specify that continuous bleed pneumatic devices installed prior to January 1, 2016 that do not vent natural gas at a rate greater than 6 standard cubic feet per hour (scfh) may remain in service provided that the devices are clearly identified with a permanent tag to identity these particular devices, and the devices are tested annually using a flow rate measurement method.

Rationale of Section 95668(f)(2)(A)1-5

This section is necessary to identify a subcategory of existing continuous bleed pneumatic devices that vent small amounts of methane and were previously installed in order to comply with ARB Mandatory Reporting Regulation requirements, which required either replacing high-bleed devices with low bleed devices or metering the gas flow rate. . The requirements listed specify how an owner or operator must identify the devices for identification by inspectors, and how the devices must be tested annually to ensure that they do not vent emissions at a rate greater than 6 scfh. Similar to other devices that require emission flow rate testing, the annual measurement frequency was chosen due to the complexity of performing flow rate measurements.

Summary of Section 95668(f)(3)

This section specifies that intermittent bleed pneumatic devices must comply with the leak detection and repair requirements when they are not controlling.

Rationale of Section 95668(f)(3)

This requirement is necessary to ensure that intermittent bleed pneumatic devices do not leak or vent natural gas when they are not controlling, a state that is also known as “idle”. By design, intermittent bleed devices are designed to be sealed, and do not vent natural gas when idle. However, they may vent a predetermined volume of natural gas when controlling a process or equipment. This requirement is designed to ensure that the devices are tested consistently by an owner or operator or inspector and to ensure that the device is sealed when idle.

Summary of Section 95668(f)(4)

This section specifies that pneumatic pumps shall not vent natural gas to the atmosphere and must be tested and repaired during each inspection period according to the proposed LDAR requirements.

Rationale of Section 95668(f)(4)

This requirement is necessary to eliminate emissions of methane from pneumatic pumps that vent natural gas into the atmosphere. Other types of non-venting pneumatic pumps are available and these pumps may be retrofitted to use compressed air or electricity to eliminate the vented emissions.

Summary of Section 95668(f)(5)

This section specifies that natural gas powered pneumatic devices and pumps must be replaced or retrofitted with the use of a vapor collection system, compressed air, or electricity to prevent the venting of natural gas emissions into the atmosphere.

Rationale of Section 95668(f)(5)

This section is necessary to inform a regulated party that the proposed regulation would require the replacement of pneumatic devices or require the devices to be retrofitted. The control strategies include controlling devices with use of a vapor collection system or modifying devices to use compressed air or electricity to operate. These options are designed to provide a regulated party with flexibility to control emissions of methane from a variety of devices and pumps.

11. Section 95668(g). Liquids Unloading of Natural Gas Wells.

Summary of Section 95668(g)

This section specifies that a regulated party who vents natural gas to the atmosphere for the purpose of liquids unloading must either control the vented natural gas with the use of a vapor collection system or measure or calculate the volume of vented gas. Regulated parties must also maintain records and report volumes of vented natural gas from liquids unloading operations and equipment installed to automatically perform liquids unloading.

Rationale of Section 95668(g)

This section is required to either (1) control emissions of natural gas that is vented as a result of liquids unloading or (2) quantify the emissions and gather information on the activity and automation equipment used to perform the operation automatically. If a regulated party chooses to control the vented natural gas, they must use a vapor collection system as specified in section 95668(c). If a regulated party chooses to measure the volume of gas that is vented they are permitted to choose from several measurement methods. A regulated party may also choose to calculate the volume of gas that is vented by using one of the specified calculation methods. If a regulated party chooses to use either one of the measurement or calculation methods, they must report the results to ARB annually. This information is necessary for ARB to accurately quantity emissions and determines the performance of automation equipment. The results will be used to determine if future modifications to the proposed regulation are necessary.

12. Section 95668(h). Well Casing Vents.

Summary of Section 95668(h)

This section specifies that by the effective date, owners or operators of wells located at facilities listed in section 95666, with a well casing vent that is open to the atmosphere shall measure the natural gas flow rate from the well casing vent annually, and according to the methods listed in the regulation. Additionally, a record of each well casing vent flow rate measurement according to Appendix A, Table 7 of the proposed regulation, should be maintained and made available to ARB's Executive Officer, annually.

Rationale of Section 95668(h)

This section is required for ARB to quantify emissions and gather information from well casing vents that are open to the atmosphere. This section is also required to notify inspectors that well casing vents that are open to the atmosphere are not subject to the LDAR standards. Each year, the owner operator must measure the volume of natural gas that is vented from each well casing vent and report the results to ARB. The results will be used to determine if future modifications to the proposed regulation are necessary.

13. Section 95668(i). Natural Gas Underground Storage Facility Monitoring Requirements.

Summary of Section 95668(i)

This section details the monitoring requirements for natural gas underground storage facilities. Operators must comply with leak detection protocols that are already in place at the effective date of this subarticle. Operators must then submit an air monitoring plan and a leak detection protocol to ARB's Executive Officer for approval. The leak detection protocol may include the daily use of Method 21, Optical Gas Imaging, or other screening instruments; or a continuous monitoring alarm system. Recordkeeping and quarterly reporting requirements are also detailed. The ambient air monitoring plan requires the use of a continuous air monitoring network. All leaks discovered must be repaired within the repair timeframes detailed in section 95669.

Rationale of Section 95668(i)

The purpose of this section is to prevent leaks in underground storage facilities from going unnoticed, neglected, or unchecked. A variety of methods to detect leaks are included in the protocol, to provide flexibility to operators in meeting requirements. Continuous ambient air monitoring is required to provide the public agencies and the public accurate exposure information.

14. Section 95669. Leak Detection and Repair.

Summary of Section 95669(a)

This section specifies the facilities that are subject to the proposed leak detection and repair requirements.

Rationale of Section 95669(a)

This section is required to inform a regulated party of the types of facilities that are subject to the proposed leak detection and repair requirements.

Summary of Section 95669(b)

This section specifies the types of equipment that are not covered by the proposed leak detection and repair requirements.

Rationale of Section 95669(b)

This section is necessary to specify components that are not subject to the proposed leak detection and testing requirements.

Summary of Section 95669(b)(1)

This section specifies that any components that are subject to local air district leak detection and repair requirements prior to January 1, 2018 are not subject to the proposed leak detection and repair requirements.

Rationale of Section 95669(b)(1)

This section is necessary to specify that, for the purposes of this proposed regulation, all components that are already tested and repaired in accordance with local air district requirements are already in compliance with this proposed regulation.

Summary of Section 95669(b)(2)

This section specifies that components, including components found on tanks, separators, and pressure vessels used exclusively with the crude oil with API gravity less than 20 are not subject to the proposed leak detection and repair requirements.

Rationale of Section 95669(b)(2)

This section is necessary to specify that the proposed leak detection and repair testing requirements do not apply to heavy oil components. Staff's analysis of published emission factors[42] to date show that components associated with heavy oil emit less total hydrocarbons, and therefore less methane, than other components found in gas or other liquid service.

Summary of Section 95669(b)(3)

This section specifies that components incorporated into produced water lines located downstream of a separator and tank system are not subject the proposed leak detection and repair requirements.

Rationale of Section 95669(b)(3)

The section is necessary to specify that components used in conjunction with produced water and which are located downstream of a separator and tank system are not subject to the proposed requirements. Staff was not able to locate any published emission factors for these components which are located downstream from the point of where flashing occurs.

[42] CAPCOA. 1999. California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities

Summary of Section 95669(b)(4)

This section specifies that natural gas distribution lines used to deliver commercial quality natural gas to a facility, and which are not owned or operated by the facility, are not subject to the proposed leak detection and repair requirements.

Rationale of Section 95669(b)(4)

This section is necessary to specify that an owner or operator is not responsible for testing or repairing components that are not owned or operated by the facility.

Summary of Section 95669(b)(5)

This section specifies that components that are buried below ground are not subject to the proposed leak detection and testing requirements and that the portion of well casing that is visible above the ground is not considered a buried component.

Rationale of Section 95669(b)(5)

This section is necessary to specify that testing is not required for buried components and prevents the need for owners or operators to uncover and test components. However, testing is required for well casing components, including the portion of well casing that is visible on the surface. In some cases it's possible for an underground well casing leak to permeate up the surface along the exterior portion of well casing. These types of leaks can be detected at well head casing on the surface and are subject to the proposed leak detection and repair requirements.

Summary of Section 95669(b)(6)

This section specifies that stainless tube fittings used in conjunction with compressed air are not subject to the proposed requirements.

Rationale of Section 95669(b)(6)

This section is necessary to prevent the need for testing components that do not contain any emissions of methane or other hydrocarbons.

Summary of Section 95669(b)(7)

This section specifies that stainless tube fittings used in conjunction with natural gas that have been tested in accordance with Method 21 do not require additional testing.

Rationale of Section 95669(b)(7)

This section is necessary to prevent the need re-testing stainless-steel tube fittings that have been previously testing. These fittings are designed with the use of a nut and ferrule locking system and are designed to not loosen or leak once tightened.

Summary of Section 95669(b)(8)

This section specifies that components operating under negative gauge pressure or below atmospheric pressure are not subject the proposed leak detection and repair requirements.

Rationale of Section 95669(b)(8)

This section is necessary to prevent the need for testing components that do not have the ability to emit methane or hydrocarbon emissions.

Summary of Section 95669(b)(9)

This section specifies that components located downstream of a custody transfer meter and are not owned by the production facility are not subject to the proposed leak detection and repair requirements.

Rationale of Section 95669(b)(9)

This section is necessary to specify that an owner or operator is not responsible for testing or repairing components that are not owned or operated by the facility.

Summary of Section 95669(b)(10)

This section specifies that components used for general maintenance and used less than 300 hours per year are not subject to the proposed leak detection and repair requirements if the owner or operator maintains a record of the components and can provide a copy of the record at the request of the ARB.

Rationale of Section 95669(b)(10)

This section is necessary to specify that temporary components are not subject to the proposed regulation requirements. These components are used to temporarily divert liquid or gases while equipment is being constructed or modified. This requirement prevents the need to perform counting and measurements on components that are only used temporarily.

Summary of Section 95669(b)(11)

This section specifies that well casing vents that are open to the atmosphere are not subject to the proposed leak detection and repair requirements.

Rationale of Section 95669(b)(11)

This section is necessary to specify that well casing vents that are open to the atmosphere are not subject to the proposed leak detection and repair requirements. However, these components are subject to the proposed annual flow rate testing and reporting requirements. This section is necessary to prevent owners or operators or inspectors from testing these components during regular leak inspections.

Summary of Section 95669(c)

This section specifies that all components not identified in the exemptions section are subject to the proposed leak detection and repair requirements beginning on January 1, 2018.

Rationale of Section 95669(c)

This section is necessary to inform a regulated party that components located at facilities which are not identified in the exemption's section are subject to the proposed regulation requirements.

Summary of Section 95669(d)

This section specifies that the ARB Executive Officer may perform inspections at facilities at any time in order to determine compliance with the proposed leak detection and repair requirements.

Rationale of Section 95669(d)

This section is necessary to inform a regulated party that ARB may perform routine inspections at facilities at any time throughout the calendar year. These inspections may be in addition to local air district inspections. This requirement is necessary for ARB to determine compliance with the proposed regulation.

Summary of Section 95669(e)

This section specifies that owners or operators must perform daily audio-visual inspections on hatches, pressure-relief valves, well casings, stuffing boxes, and operating pump seals to look for the presence of leaks. The daily inspection frequency is reduced to weekly for unmanned facilities.

Rationale of Section 95669(e)

This section is necessary to inform a regulated party that audio-visual inspections are required for specified components. This requirement is similar to current requirements used by local air districts in major oil and gas producing regions. Each of the components listed have the potential to emit large amounts of methane so this requirement is necessary to ensure that these components do not leak for extended periods of time, or continue to leak in between routine instrument inspections. The list of components was shortened to only the most critical components so that an owner or operator has the ability to perform simple audio-visual checks when they visit the facilities.

Summary of Section 95669(e)(1)

This section specifies that all pipes installed at a facility must be audio-visually checked at least once every 12 months.

Rationale for Section 95669(e)(1)

This section is necessary to inform a regulated party that audio-visual inspections are required for all pipes located at a facility at least once every twelve months. This requirement is similar to current requirements used by local air districts in major oil and gas producing regions. This requirement is necessary to ensure that all gathering pipes used at a facility are inspected. Although pipes are designed not to leak emissions, they are also not routinely inspected with the use of Method 21 which is primary used for measuring connections. This requirement is necessary to ensure that pipes are checked for damage and repaired within 24 hours or tested with the use of Method 21 and repaired within the specified timeframes.

Summary of Section 95669(f)

This section specifies that any audio-visual inspection that indicates a leak that cannot be repaired within 24 hours must be measured with the use of Method 21 and then repaired within the timeframe specified for the resulting leak concentration measurement. Provisions have been made to clarify the testing requirement for leaks discovered over weekends or holidays.

Rationale for Section 95669(f)

This section is necessary to specify resulting actions that are required by an owner or operator if a leak is discovered during an audio-visual inspection. In many cases leaks can be repaired immediately, but some leaks require more complex repairs. The measurement requirement is necessary to identify the leak concentration which is used to determine the repair timeframe.

Summary of Section 95669(g)(1)

This section specifies that components must be tested in accordance with EPA Reference Method 21 at least once each calendar quarter and that the quarterly inspections may be reduced to annual inspections if a facility maintains compliance for five consecutive calendar quarters. The annual inspection frequency will revert back to quarterly if the facility fails to maintain compliance with the proposed requirements.

Rationale of Section 95669(g)(1)

This section is necessary to specify the proposed test method and the proposed leak inspection frequency. The EPA Reference Method 21 provides a reliable means of quantifying leaks and is currently in use by local air districts in major oil and gas producing regions. Accurately quantifying leaks is critical to determining compliance with the specified leak thresholds and repair timeframes. This section is also necessary to specify criteria that determine the leak inspection frequency after five consecutive calendar quarters. The proposed option for compliant facilities to conduct annual inspections is similar to current requirements used by local air districts in major oil and gas producing regions. This option provides an incentive for facilities to find and repair leaks quickly and also prevents the need for unnecessary instrument-based inspections at compliant facilities. In the event that a facility is determined to be out of compliance with the proposed requirements, either by way of an ARB or local air district inspection or by way of an inspection conducted by the owner or operator, the facility must revert back to quarterly inspections.

Summary of Section 95669(g)(2)

This section specifies that Optical Gas Imaging (OGI) instruments may be used to screen for leaks at a facility if they are approved for use by the local air district and used by a technician with minimum Level II Thermographer training. All leaks detected with these instruments must be measured with the use of Method 21 within the timeframes specified in order to quantify the leak concentration and determine the appropriate repair timeframes.

Rationale of Section 95669(g)(2)

This section is necessary to specify that OGI instruments may be used as a screening device to locate leaks if all of the specified conditions are met. Some owners or operators may find it useful to use these instruments in order to assist with leak inspections or to locate leaks in hard to reach places. Special provisions have been included that require local district approval and the need for specialized OGI instrument training. The training requirement is necessary because there are special conditions required for using OGI instruments and reading the images that they create. This section is also necessary to specify that all leaks detected with the use of an OGI instrument must be tested with the use of Method 21. This requirement is necessary to accurately determine the component leak concentration and repair timeframe.

Summary of Section 95669(h) and (i)

These sections specify the proposed leak thresholds and repair timeframes that apply to regulated facilities subject to the proposed regulation. Under this proposal, leaks that are measured with a total hydrocarbon concentration above the leak threshold are required to be repaired within the designated timeframe. Two different minimum leak threshold standards are required under this regulation proposal. Beginning January 1, 2018, the minimum leak threshold is greater than or equal to 10,000 parts per million by volume (ppmv), and beginning January 1, 2020, the minimum leak threshold is greater than or equal to 1,000 ppmv. The proposed repair time periods are the same for each minimum leak threshold providing 14 calendar days for a regulated party to make repairs. These proposed repair time periods do not apply to critical components which are provided additional time to make repairs.

Rationale of Section 95669(h) and (i)

These requirements are necessary to eliminate methane emissions from components such as valves, flanges, and fittings. Emissions from these components may occur from the effects of weathering when bolts may naturally loosen or when components wear out. The proposed leak thresholds and repair timeframes are similar to those used by local air districts for oil and gas facilities in major oil and gas producing regions. The minimum leak threshold between the 2018 and 2020 calendar years are intended to provide owners or operators with time to repair any large leaks found at their facilities. These minimum leak thresholds are higher than similar leak thresholds used by local air districts. After January 1, 2020, facilities must comply with lower leak thresholds which resemble those currently used by local air districts.

Summary of Section 95669(j)

This section specifies how a leaking component must be identified with a weatherproof tag, which identifies the date that the inspection was conducted and the leak concentration measurement. The tag must remain affixed to the component until it has been repaired and retested to verify that it is no longer leaking above the minimum leak threshold standard.

Rationale of Section 95669(j)

This section is required so that a regulated party and inspectors can track component leaks measured above leak concentration thresholds, and reduces the possibility that a leaking component will be double-counted during any inspection period. Each tag is required to remain affixed to the component until it has been fully repaired and tested to demonstrate it does not leak above the proposed minimum leak threshold.

<u>Summary of Section 95669(k)</u>

This section specifies that a regulated party must maintain a record of each leak detection and repair inspection including the leak concentration measurement and repair date(s) or components. It also requires that regulated parties must report this information to ARB once per calendar year, as well as making records available to the Executive Officer upon request.

<u>Rationale of Section 95669(k)</u>

This section is necessary to document the results of the leak detection and repair inspections and components awaiting repairs. This allows both the regulated party and inspectors to verify compliance with the proposed regulation and to ensure that all components are repaired within the timeframes.

<u>Summary of Section 95669(l)</u>

This section specifies that hatches must be closed at all times except during sampling, process material, or attended maintenance operations.

<u>Rationale of Section 95669(l)</u>

This requirement is necessary to ensure that unattended pressure vessels, separators, and tanks do not emit methane emissions. The emissions may occur as a result of an automated process, such as when liquids are automatically transferred to a tank or vessel, or when liquids are stored for an extended period. The requirement allows for hatches to be open during routine activities so that a regulated party may enter a vessel to perform routine maintenance or sampling.

<u>Summary of Section 95669(m)</u>

This section specifies requirements for open-ended lines or valves located at the end of lines used at facilities subject to the proposed regulation requirements.

<u>Rationale of Section 95669(m)</u>

This requirement is necessary to prevent the release of methane from open ended lines or valves that have one side of a valve seat open to the atmosphere. This requirement is designed to ensure that all valves are sealed as intended and do not solely rely on the valve seat to prevent the release of emissions. Provisions are included to allow the owner or operator to use the valve as intended, but the valve must sealed when not being used.

Summary of Section 95669(n)

This section specifies that components or component parts that incur five repair actions within a continuous 12 month period must be replaced.

Rationale of Section 95669(n)

This section is necessary to ensure that documented faulty or defective components are replaced to eliminate methane emissions. In some cases, these components may emit methane in between regular leak detection and repair inspections. This requirement is necessary to address faulty components that cannot be repaired by simple adjustment, such as tightening bolts that have loosened due to weathering.

Summary of Section 95669(o)

This section specifies that a regulated party must comply with all of the proposed leak detection requirements specified in the proposed regulation, and specifies the beginning compliance dates, leak thresholds, and percentage of leaks that are allowed during each compliance period. Failure to meet the requirements shall constitute a violation of the proposed regulation requirements.

Rationale of Section 95669(o)

This section is necessary to specify the leak detection and repair standards and to notify a regulation party that failure to meet any of the requirements constitutes a violation of the proposed regulation. Table 3 identifies the proposed compliance requirements for the first year of leak detection and testing, and Table 4 identifies the requirements beginning January 1, 2019 and thereafter.

15. Section 95670. Critical Components.

Summary of Section 95670(a)

This section specifies that by the proposed date, or within 180 days from installation, critical components must be pre-approved by ARB.

Rationale of Section 95670(a)

This section is necessary to inform a regulated party that all critical components must be pre-approved by ARB. Critical components are those that receive additional time to make repairs, which can be up to 12 months from the date of initial leak detection or the next time that the equipment is shut down or removed from service.

Summary of Section 95670(b)

This section specifies that a regulated party must provide sufficient documentation demonstrating that a critical component is part of critical process unit and that removing the component within the proposed repair timeframes would result in excessive methane emissions or would impact the safety or reliability of the system.

Rationale of Section 95670(b)

This requirement is necessary so that a regulated party can adequately demonstrate that a critical component is part of a critical process unit.

Summary of Section 95670(c)

This section specifies that requests for critical components are made by submitting records and documentation to ARB as specified.

Rationale of Section 95670(c)

This section is necessary to provide a regulated party with instructions for submitting a request for a critical component designation.

Summary of Section 95670(d)

This section specifies that a regulated party must maintain a record of all critical components installed at the facility and must be able to make the record available upon request by the ARB or local air district inspector.

Rationale for Section 95670(d)

This section is necessary to inform a regulated party that records of critical components must be maintained at the facility and made available upon request by ARB or the local air district inspector. These records are necessary to provide documentation for use in determining compliance with the proposed leak repair timeframes.

Summary of Section 95670(e)

This section specifies that all critical components must be identified with a weatherproof, readily visible tag, indicating that they are pre-approved ARB critical components.

Rationale of Section 95670(e)

This section is necessary to inform a regulated party that all critical components must be clearly identified. This requirement is necessary so that ARB or local air district inspectors can easily verify these components during routine inspections and determine compliance with the proposed leak repair timeframes.

Summary of Section 95670(f)

This section specifies that approval of critical components may be granted if all of the requirements listed in Section 95670 are met, and that ARB reserves discretion to deny a critical component approval.

Rationale of Section 95670(f)

This section is necessary to inform a regulated party that ARB may deny a request for critical component approval. This requirement is needed to provide ARB with the discretion to evaluate, and re-evaluate if needed, all critical components to ensure that they are the part of a critical process unit and that repairing such component within the proposed repair timeframes would result in excessive methane emissions or would impact the safety or reliability of the system.

16. Section 95671. Record Keeping Requirements.

Summary of Section 95671(a)(1)

This section specifies that a record of flash analysis testing, including a sketch or drawing of the separator and tank system, laboratory reports, calculations, and field testing forms must be maintained for five years.

Rationale of Section 95671(a)(1)

This section is necessary to list all of the information required to adequately document the results of flash analysis testing and to document any changes in the system configuration or annual methane emissions. This information is also used by ARB or a local air district inspector to determine compliance with the proposed regulation standard.

Summary of Section 95671(a)(2)

This section specifies that a record of each leak concentration measurement for a reciprocating compressor rod packing or seal that is measured above the minimum leak threshold is recorded as specified in Appendix A, Table A5 of the proposed regulation and maintained for at least five years.

Rationale of Section 95671(a)(2)

This requirement is necessary to list information that is required to adequately document the results of emissions testing. This information is required by ARB to maintain accurate records of leak concentration measurements from these particular components and is also used by ARB or local air district inspectors to verify compliance with the proposed regulation requirements.

Summary of Section 95671(a)(3)

This section specifies that a record of each reciprocating compressor rod packing or seal emission flow rate measurement must be recorded as specified in Appendix A, Table A7 of the proposed regulation and maintained for at least five years.

Rationale of Section 95671(a)(3)

This requirement is necessary to list information that is required to adequately document the results of emissions flow rate testing. This information is required by ARB to maintain accurate records of emission flow rate measurements from these particular components and is also used by ARB or local air district inspectors to verify compliance with the proposed regulation requirements.

Summary of Section 95671(a)(4)

This section specifies that a record of each centrifugal compressor wet seal emission flow rate measurement must be recorded as specified in Appendix A, Table A7 of the proposed regulation and maintained for at least five years.

Rationale of Section 95671(a)(4)

This requirement is necessary to list information that is required to adequately document the results of emissions flow rate testing. This information is required by ARB to maintain accurate records of emission flow rate measurements from these particular components and is also used by ARB or local air district inspectors to verify compliance with the proposed regulation requirements.

Summary of Section 95671(a)(5)

This section specifies that a record of each pneumatic device emission flow measurement must be recorded as specified in Appendix A, Table A7 of the proposed regulation and maintained for at least five years.

Rationale of Section 95671(a)(5)

This requirement is necessary to list information that is required to adequately document the results of emissions flow rate testing. This information is required by ARB to maintain accurate records of emission flow rate measurements from these particular components and is also used by ARB or local air district inspectors to verify compliance with the proposed regulation requirements.

Summary of Section 95671(a)(6)

This section specifies that each liquids unloading measurement or calculation must be recorded as specified in Appendix A, Table A7 of the proposed regulation and maintained for at least five years.

Rationale of Section 95671(a)(6)

This requirement is necessary to list information that is required to adequately document the results of liquids unloading activities. This information is required by ARB to maintain accurate records of liquids unloading activities and is also used by ARB or local air district inspectors to verify compliance with the proposed regulation requirements.

Summary of Section 95671(a)(7)

This section specifies that a record of each well casing flow measurement must be recorded as specified in Appendix A, Table A7 of the proposed regulation and maintained for at least five years.

Rationale of Section 95671(a)(7)

This requirement is necessary to list information that is required to adequately document the results of emissions flow rate testing. This information is required by ARB to maintain accurate records of emission flow rate measurements from these particular components and is also used by ARB or local air district inspectors to verify compliance with the proposed regulation requirements.

Summary of Section 95671(a)(8)

This section specifies that a record of each leak concentration measurement for leaks identified during daily inspections or identified by a continuous leak monitoring system and subsequently measured above the minimum leak threshold is recorded as specified in Appendix A, Table A5 of the proposed regulation and maintained for at least five years.

Rationale of Section 95671(a)(8)

This requirement is necessary to document leaks that have been identified during daily inspections or identified by a continuous monitoring system and demonstrate that they have been tested and repaired within the proposed repair timeframes. This information is required by ARB to maintain accurate records of leak concentration measurements and is also used by ARB or local air district inspectors to verify compliance with the proposed regulation requirements.

Summary of Section 95671(a)(9)

This section specifies that a record of the number of leaks identified during inspections for each leak threshold category is recorded as specified in Appendix A, Table A4 of the proposed regulation and maintained for at least five years.

Rationale of Section 95671(a)(9)

This requirement is necessary to document the number of leaks identified during a leak inspection for each leak threshold category in order to determine compliance with the proposed regulation requirements,

Summary of Section 95671(a)(10)

This section specifies that a record of each leak initial and final leak concentration and repair date is recorded as specified in Appendix A, Table A5 of the proposed regulation and maintained for at least five years.

Rationale of Section 95671(a)(10)

This requirement is necessary to document all components that have been measured above the minimum leak threshold. This information is required by ARB to maintain accurate records of leak concentration measurements and is also used by ARB or local air district inspectors to verify compliance with the proposed regulation requirements.

17. Section 95672. Reporting Requirements

Summary of Section 95672(a)(1)

This section specifies that within 90 days of performing flash analysis testing or recalculating annual methane emissions, the results must be reported to ARB as specified in Appendix A, Table A1 of the proposed regulation.

Rationale for Section 95672(a)(1)

This information is required by ARB to maintain accurate records of these activities and is also used by ARB or a local air district to determine compliance with the proposed requirements.

Summary of Section 95672(a)(2)

This section specifies that a record of each rod packing or seal leak concentration measurement that is above the minimum allowable leak threshold must be reported to ARB annually as specified in Appendix A, Table A5 of the proposed regulation.

Rationale for Section 95672(a)(2)

This information is required by ARB to maintain accurate records of these activities and is also used by ARB or a local air district to determine compliance with the proposed requirements.

Summary of Section 95672(a)(3)

This section specifies that a record of each rod packing or seal emission flow rate measurement must be reported to ARB annually as specified in Appendix A, Table A7 of the proposed regulation.

Rationale for Section 95672(a)(3)

This information is required by ARB to maintain accurate records of these activities and is also used by ARB or a local air district to determine compliance with the proposed requirements.

Summary of Section 95672(a)(4)

This section specifies that a record of each centrifugal compressor wet seal emission flow rate measurement must be reported to ARB annually as specified in Appendix A, Table A7 of the proposed regulation.

Rationale for Section 95672(a)(4)

This information is required by ARB to maintain accurate records of these activities and is also used by ARB or a local air district to determine compliance with the proposed requirements.

Summary of Section 95672(a)(5)

This section specifies that a record of each pneumatic device emission flow rate measurement for devices with a designed flow rate of less than 6 standard cubic feet per hour must be reported to ARB annually as specified in Appendix A, Table A7 of the proposed regulation.

Rationale for Section 95672(a)(5)

This information is required by ARB to maintain accurate records of these activities and is also used by ARB or a local air district to determine compliance with the proposed requirements.

Summary of Section 95672(a)(6)

This section specifies that the measured or calculated volume of natural gas that is vented to perform liquids unloading must be reported to ARB annually as specified in Appendix A, Table A3 of the proposed regulation.

Rationale for Section 95672(a)(6)

This information is required by ARB to maintain accurate records of these activities and is also used by ARB or a local air district to determine compliance with the proposed requirements.

Summary of Section 95672(a)(7)

This section specifies that a record of each well casing emission flow rate measurement must be reported to ARB annually as specified in Appendix A, Table A7 of the proposed regulation.

Rationale for Section 95672(a)(7)

This information is required by ARB to maintain accurate records of these activities and is also used by ARB or a local air district to determine compliance with the proposed requirements.

Summary of Section 95672(a)(8)

This section specifies that within 24 hours of identifying a leak that is measured above the maximum allowable leak threshold at each underground injection/withdrawal well wellhead assembly, attached pipelines, and the surrounding area within a 200 foot radius of the wellhead, the regulated party must contact ARB, the Department of Oil, Gas, and Geothermal Resources, and the local air district to report the leak concentration measurement.

Rationale for Section 95672(a)(8)

This requirement is necessary to notify ARB and other appropriate agencies of a leak concentration measurement found at or near a wellhead assembly that exceeds the maximum allowable standard and potentially signals a well failure. This requirement is necessary to ensure that all appropriate agencies are notified promptly so that appropriate action may be taken.

Summary of Section 95672(a)(9)

This section specifies that within 24 hours of receiving an alarm signaled by an air monitoring system that detects levels of natural gas that exceed more than 10 percent of baseline conditions that the regulated party must contact ARB, the Department of Oil, Gas, and Geothermal Resources, and the local air district to report the leak concentration measurement.

Rationale for Section 95672(a)(9)

This requirement is necessary to notify ARB and other appropriate agencies of an alarm that exceeds baseline conditions and potentially signals a well failure. This requirement is necessary to ensure that all appropriate agencies are notified promptly so that appropriate action may be taken.

Summary of Section 95672(a)(10)

This section specifies that a record of all leaks identified during daily inspections or identified by a continuous leak monitoring systems and that are measured above the minimum leak threshold must be reported to ARB quarterly as specified in Appendix A, Table A5 of the proposed regulation.

Rationale for Section 95672(a)(10)

This information is required by ARB to maintain accurate records of leaks identified at or near an underground injection/withdrawal well wellhead assembly and is also used by ARB or a local air district to determine compliance with the proposed requirements.

Summary of Section 95672(a)(11)

This section specifies that the results of leak detection and repair inspections conducted during each calendar quarter must be reported to ARB annually as specific in Appendix A, Table A4 of the proposed regulation.

Rationale for Section 95672(a)(11)

This information is required by ARB to maintain accurate records of these activities and is also used by ARB or a local air district to determine compliance with the proposed requirements.

Summary of Section 95672(a)(12)

This section specifies that the initial and final leak concentration measurement for each leak measured above the minimum allowable leak threshold must be reported to ARB annually as specific in Appendix A, Table A5 of the proposed regulation.

Rationale for Section 95672(a)(12)

This information is required by ARB to maintain accurate records leak inspection activities and is also used by ARB or a local air district to determine compliance with the proposed requirements.

Summary of Section 95672(b)

This section specifies the mailing address and electronic mailing address for ARB.

Rationale for Section 95672(b)

This section is necessary to provide contact information so that reports can be submitted to ARB.

18. Section 95673. Implementation.

Summary of Section 95673(a)(1)

This section specifies that the requirements of the proposed regulation are provisions of state law that are enforceable by both ARB and local air districts, and that a regulated party must pay fees required by a local air district to implement and enforce the proposed requirements, including fees associated with enforcement penalties. Enforcement action penalties secured by local air districts may be retained by the district.

Rationale for Section 95673(a)(1)

This section is necessary to clarify that the proposed regulation is enforceable by both ARB and the local air districts, and that a local air district may charge fees associated with implementing or enforcing the requirements, that regulated parties are responsible for paying the fees, and that local air districts may retain the funds.

Summary of Section 95673(a)(2)

This section specifies that the ARB Executive Officer may enter into an agreement with a local air district to further define implementation and enforcement requirements or to establish formal information sharing procedures.

Rationale for Section 95673(a)(2)

This section is necessary to make clear that ARB and local air districts may enter into formal written agreements, such a Memorandum of Understanding or Agreement, which may further define the implementation or enforcement procedures. Providing for such agreements is necessary to implementing the regulation in a flexible and cost-effective manner, and supports efficient use of ARB and air district resources. These agreements can be developed to provide a formal process for sharing confidential information such as registration or permit records, inspection or enforcement records, or collected test data.

Summary of Section 95673(a)(3)

This section specifies that implementation and enforcement by a local air district may not result in a standard, requirement, or prohibition that is less stringent than any of the requirements listed in the proposed regulation.

Rationale for Section 95673(a)(3)

This section is necessary to specify that the proposed regulation sets the minimum standards and requirements for regulated parties. In no instance may a local air district issue a registration or permit used on less stringent standards or requirements or adopt rules that result in less stringent standards or requirements, which are less stringent than the proposed requirements. This is necessary to ensure that this statewide regulation is implemented in a uniform manner, ensuring consistent emissions benefits and costs for regulated entities.

Summary of Section 95673(a)(4)

This section specifies that implementation and enforcement of the proposed regulation by a local air district does not waive or limit ARB's authority to implement or enforce any of the requirements specified. It further specifies that a facility's permitting or registration status does not otherwise limit the ability of a local air district to enforce applicable requirements.

Rationale for Section 95673(a)(4)

This section is necessary to clarify that both ARB has the ability to implement and enforce each of the provisions specified in this proposed regulation. It is also necessary to clarify that facilities subject to compliance with this article may be subject to local air district enforcement regardless of permitting or registration status.

Summary of Section 95673(b)(1)

This section specifies that a regulated party currently required to maintain a local air district permit for a facility or equipment due to federal, state, or local requirements must apply for these permits to be amended to include the terms specified in the proposed regulation and that future local air district requirements do not alter these provisions.

Rationale for Section 95673(b)(1)

This section is necessary so that a regulated party, as well as other federal, state, and local entities, understand that the terms and conditions of this proposed regulation must be included in any existing permit that covers affected facilities or equipment and that future changes to those permits do not alter the proposed regulation requirements.

Summary of Section 95673(b)(2)

This section specifies the registration requirements for facilities or equipment covered by the proposed regulation, which include registration with ARB, unless a local air district collects the required information and enters into an agreement to share it with ARB.

Rationale for Section 95673(b)(2)

This section is necessary to specify that facilities or equipment covered by the proposed registration must register equipment with ARB. This section specifies all required information. This section is also necessary to make clear that air districts may take on the registration program, obviating the need for separate registration with ARB.

Summary of Section 95673(b)(3)

This section specifies that owners and operators subject to the proposed regulation must comply with all of its requirements, even if they have not complied with any of the permitting and registration requirements of section 95673.

Rationale for Section 95673(b)(3)

This section is necessary to make clear that even if permitting and registration requirements are not fulfilled, the substantive standards and requirements of the proposed regulation still apply. This will ensure that any confusion over these compliance requirements does not act as an excuse to compromise emission reductions.

19. Section 95674. Enforcement.

Summary of Section 95674

This section specifies the types of violations that may occur under this proposed regulation. Subsection (a) specifies that each violation at each individual piece of equipment constitutes a separately enforceable violation. Subsection (b) specifies that each day or portion of a day that compliance is not maintained is a separate violation. Subsection (c) specifies that each metric ton of methane emitted in violation of the proposed regulation will constitute a separately enforceable violation. Subsection (d) specifies that failure to submit any required report will constitute a violation, and that each day a report is late will constitute a violation. Subsection (e) specifies that failures to retain required records and failures to produce records will constitute violations for each record, and for each day production is late. Subsection (f) specifies that producing inaccurate information is a violation of the proposed regulation._Subsection (g) specifies that submitting or producing false information is a violation of the proposed regulation.

Rationale for Section 95674

This section is required to specify that failure to comply with any of the proposed requirements is subject to enforcement action. Each enforcement provision is clearly specified so the proposed regulation is not interpreted in such a way to mean that a regulated party is not subject to enforcement action.

20. Section 95675. No Preemption for More Stringent Air District or Federal Requirements.

Summary of Section 95675

This section specifies that the proposed regulation does not preempt more stringent federal or local requirements.

Rationale for Section 95675

This section is required so that the proposed regulation is not interpreted in such a way to mean that any more stringent federal or local requirement do not apply to an entity subject to this proposed regulation.

21. Section 95676. Severability.

Summary of Section 95676

This section specifies that each part of the proposed regulation is severable.

Rationale for Section 95676

This section is necessary so that the proposed regulation is not interpreted in such a way to mean that a future determination, which invalidates any part of the proposed regulation, does not invalidate any of the other requirements.

22. Appendix A.

Summary of Appendix A, Table A1

This table specifies data that must be recorded at the time each flash analysis test is conducted.

Rationale for Appendix A, Table A1

This table is required to document the results of flash analysis testing and to adequately describe the separator and tank system at the time of testing. This table is also used to report results to ARB as specified and to determine compliance with the proposed regulation requirements.

Summary of Appendix A, Table A2

This table specifies data that must be recorded each time a liquids unloading activity is conducted.

Rationale of Appendix A, Table A2

This table is required to document the results of liquids unloading activities. This table is also used to report results to ARB as specified and to determine compliance with the proposed regulation requirements.

Summary of Appendix A, Table A3

This table specifies the minimum amount of information that must be provided to ARB each time an owner or operator makes a request for a critical component designation.

Rationale of Appendix A, Table A3

This table is required to submit information to ARB for critical component approval request. This table is used by a regulated party and ARB or local air district inspectors to maintain records of all critical components located at a facility and verify component repair timeframes.

Summary of Appendix A, Table A4

This table specifies test data that must be recorded during each leak detection and repair inspection.

Rationale of Appendix A, Table A4

This table is required to list the number of leaks found in each leak threshold category in order to determine compliance with the proposed leak detection and repair requirements.

Summary of Appendix A, Table A5

This table specifies the initial and final leak concentration measurements of each component that is found leaking above the minimum leak threshold.

Rationale of Appendix A, Table A5

This table is necessary to document components that are found leaking above the minimum leak threshold and to verify that the leak is either awaiting repairs or has been repaired and re-tested to verify that the component is not leaking above the minimum leak threshold.

Summary of Appendix A, Table A6

This table specifies the data that is required to register equipment at facilities with ARB.

Rationale of Appendix A, Table A6

This table is required to provide the ARB with adequate information to maintain records of equipment installed at facilities. This information will be used to assist ARB with conducting routine inspections and provide AB with accurate records of equipment installed at facilities.

Summary of Appendix A, Table A7

This table specifies the data that is required when conducting emission flow rate measurements.

Rationale of Appendix A, Table A7

This data is required to adequately document the results of emission flow rate measurements. This table is also used to report results to ARB as specified and to determine compliance with the proposed regulation requirements.

23. Appendix B.

Summary of Appendix B

This section specifies the approved methodology for determining vented natural gas volume from liquids unloading of natural gas wells.

Rationale for Appendix B

This appendix is necessary to provide owners and operators with the calculation specified in the proposed regulation.

24. Appendix C.

Test Procedure for Determining Annual Flash Emission Rate of Methane from Crude Oil, Condensate, and Produced Water

Summary of Section 1

This section specifies that the intended purpose of the test procedure is to quantify emissions from crude oil, condensate, and produced water and that it is applicable for use on separator and tank systems.

Rationale of Section 1

This section is required to inform a regulated party of the intended purpose and applicability of the test procedure.

Summary of Section 2

This section describes the test procedure and specifies that testing is conducted by gathering pressurized liquid samples upstream of a separator and tank system. The intent of the test procedure is to replicate flashing inside of a separator and tank system. Therefore, samples must be gathered upstream of the system before emissions can flash from the liquid. After the samples are gathered, they are taken to a laboratory for conducting liquid and gas analyses in accordance with specified test methods and procedures. After the laboratory completes the analyses, the annual methane emissions are calculated using the laboratory results and a calculation methodology.

Rationale of Section 2

This section is required to provide a summary of the test procedure so that a regulated party can understand the test procedure concept.

Summary of Section 3

This section proposes definitions to the terms used in the test procedure.

Rationale of Section 3

It is necessary that ARB defines its terms as they apply to the test procedure.

Summary of Section 4

This section provides a list of each item that may create a bias, or errors, in the final reported results. A bias in the reported results can be introduced by using an incorrect sampling method, gathering samples from the wrong location or type of vessel, using the wrong type of sampling cylinder, or using un-calibrated equipment.

Rationale of Section 4

This section is necessary to inform a regulated party with a list of each bias that has been identified with the procedure so they can avoid errors that will affect the final reported results.

Summary of Section 5

This section provides a list of minimum equipment specifications for equipment that is used to take measurements from liquid that is collected from a pressurized separator.

Rationale of Section 5

This section is required so that all field measurements are performed using instruments that provide a minimum degree of accuracy and provide consistency in the final reported results.

Summary of Section 6

This section specifies the minimum equipment specifications required to gather liquid samples from a pressurized separator. The equipment includes pressure and temperature gauges, sampling cylinders, and high pressure rated fittings. This section also specifies the need for a portable pressurized separator in the event that no pressurized separator is installed within the separator and tank system. The portable pressurized separator is optional if a pressurized separator is installed and located immediately upstream of the separator and tank system.

Rationale of Section 6

This section is required so that a regulated party can obtain all equipment necessary to conduct the liquid sampling procedure.

Summary of Section 7

This section specifies that a sampling technician must be provided with specific information by the owner or operator at the time of liquid sampling. A list of the required information is provided which includes a system identification number, the daily crude oil and produced water throughput, number of wells in the system, and the days of operation per year.

<u>Rationale of Section 7</u>

This section is required to inform a regulated party that information must be provided to the sampling technician at the time of liquid sampling. The information is required at the time of sampling because the characteristics of a separator and tank system can change daily, and any change in the parameters will affect the final reported results. Failure to provide the technician with the required information at the time of sampling will prevent the laboratory from conducting its analysis and will not provide the information necessary to calculate the annual methane emissions and report the final results.

<u>Summary of Section 8</u>

This section specifies procedures for using a Double Valve sampling cylinder to collect samples of crude oil or produced water. Depending on the liquid gathered, the cylinder is pre-filled with the specified liquid and sample liquid is introduced in the orientation as shown. Prior to gathering a sample, liquid must be purged through the sampling train into a suitable waste container to prevent filling the cylinder with air or other containments and to ensure that representative liquid is gathered.

<u>Rationale of Section 8</u>

This section is required to instruct a sampling technician on the proper method used for collecting crude oil or produced water using a Double Valve cylinder. This section is intended to provide detailed instructions to prevent sample collection bias and to prevent errors in final the reported results.

<u>Summary of Section 9</u>

This section specifies procedures for using a Piston Cylinder to collect samples of condensate or produced water. The Piston Cylinder may only be used to collect light hydrocarbon liquids or water because heavy crude oil can solidify and damage the cylinder, which will also prevent the laboratory from extracting the liquid. Prior to gathering a sample, liquid must be purged through the sampling line into a suitable waste container to prevent filling the cylinder with air or containments, and to ensure that representative liquid is gathered.

<u>Rationale of Section 9</u>

This section is required to instruct a sampling technician on the proper method used for collecting condensate or produced water using a Piston

Cylinder. This section is intended to provide detailed instructions to prevent sample collection bias and to prevent errors in final the reported results.

Summary of Section 10.1

This section specifies the laboratory quality control and quality assurance requirements required to conduct the test procedure. Each day of sampling, the laboratory must gather at least one sample duplicate. This way the lab can ensure consistency with their instruments and ensure that samples are collected in accordance with the test procedure. All deviations in measurements must be documented by the laboratory to provide a record of the deviation and explain discrepancies in reported results. Each laboratory must train its technicians on the sampling methods contained in the test procedure and must maintain records associated with sampling.

Rationale of Section 10.1

This section is required to maintain consistency in reported results from each of the separator and tank systems measured and to maintain consistency amongst the different laboratories performing the test procedure.

Summary of Section 10.2

This section lists the equipment specifications and practices required to conduct the flash analysis procedure. The minimum reporting limit for a gas chromatograph system is 100ppm for hydrocarbon and fixed gases. This provides for sufficient accuracy when reporting annual methane emissions. The equipment must be able to heat samples to the same temperature of the separator and tank system and have the ability to measure gas volume, temperature, and pressure.

Rationale of Section 10.2

This section is required to provide consistency amongst laboratories performing the laboratory flash analysis procedure. These specifications can accommodate different instruments, system configurations, and procedures used by different laboratories while ensuring consistency in final reported results

Summary of Section 10.3

This section specifies how a laboratory conducts the flash analysis procedure required to calculate the gas to oil or gas to water ratio. This includes procedures for how to heat and depressurize a sampling cylinder, collect flash gas, and analyze the gas for methane and other gaseous compounds. The procedure also includes a requirement that at least 0.20 cubic feet of gas is required to conduct test methods specified in the test procedure. After a flash analysis procedure is completed, the laboratory must completely drain the cylinder and measure the volume of liquid to calculate the gas to oil or gas to water ratio.

<u>Summary of Section 10.3</u>

This section is required to ensure consistency among different laboratories conducting the flash analysis procedure. A minimum gas volume is required so that all of the instruments can be purged of air or contaminants and eliminates error in the final reported results. The minimum gas volume requirement is listed in this section because this is the point when a laboratory will discover how much gas is entrained in the liquid.

<u>Summary of Section 10.4</u>

This section specifies the calculation methodology used by the laboratory to calculate a gas to oil or gas to water ratio.

<u>Rationale of Section 10.4</u>

This section is necessary to specify the calculations that must used by a laboratory to calculate a gas to oil or gas water ratio. This section is required to ensure consistency in reported results.

<u>Summary of Section 10.5</u>

This section specifies the laboratory methods required to conduct the test procedure.

<u>Rationale of Section 10.5</u>

This section is necessary to specify laboratory methods required to conduct the test procedure and to ensure consistency in reported results.

<u>Summary of Section 11</u>

This section specifies the calculation methodology required to calculate the annual methane emissions using a gas to oil or gas to water ratio and a gas composition analysis provided by a laboratory in conjunction with the separator and tank system throughput obtained at the time of liquid sampling.

<u>Rationale of Section 11</u>

This section is necessary to specify the calculations required to calculate the annual methane emissions and ensure consistency in reported results.

Summary of Section 12

This section specifies records that must be compiled and maintained by a laboratory conducting the test procedure. These records include a field data collection form each sample gathered, a sketch or diagram of the separator and tank systems, laboratory reports, and other information necessary to support the reported results.

Rationale of Section 12

This section is necessary to properly document all records associated with conducting the test procedure. In the event that the reported results do not represent the results of similar systems, the ARB Executive Officer or the owner or operator can contact the laboratory to evaluate the reported results and investigate possible sources of discrepancy.

Summary of Section 13

This section specifies that the test procedure must be conducted as specified and that alternative test procedures or laboratory methods used to report annual methane emissions must receive ARB Executive Officer approval. Any alternative procedures or methods will be evaluated by ARB on a case-by-case basis and a record of any approval will be maintained by ARB and made available upon request.

Rationale of Section 13

This section is necessary to specify that the test procedure must be conducted as specified and that alternative procedures or methods cannot be used without prior ARB Executive Officer approval. This section is required to ensure consistency in reported results.

Summary of Form 1

This section specifies the laboratory methods or procedures required to conduct the test procedure.

Rationale of Form 1

This section is necessary to document all applicable test methods and procedures used to conduct the test procedure and to ensure consistency in reported results.

III. ALTERNATIVES TO THE PROPOSED SOLUTION

Staff considered four alternatives to the proposed regulation that would be less burdensome to the affected industry. These alternatives are not the same as the alternatives in the Environmental Analysis, since those alternatives address reducing the environmental impacts of the proposed regulation while these alternatives address Administrative Procedure Act considerations. It is important to note that these alternatives are in addition to those that staff considered at the SRIA phase of this regulation, which are identified in that document.

A. ALTERNATIVE 1 – No Action

The first alternative is to not propose the regulation. Obviously, this would be less burdensome to the industry. However, this alternative does not achieve the goal of reducing methane emissions from the oil and natural gas production, processing, and storage sector. Accordingly, this alternative was rejected.

B. ALTERNATIVE 2 – Implement the Regulation without the LDAR Provision

The second alternative is to not propose the LDAR requirement in the regulation. This provision of the proposed regulation affects the most facilities and can be a labor intensive control measure. However, it also is the provision that achieves the largest amount of emission reductions, accounting for more than a third of the anticipated methane emission reductions. LDAR is also at the heart of catching small leaks before they become larger leaks. In addition, LDAR is key to making sure that other provisions of the regulation are operating properly, such as vapor recovery on separator and tank systems, thereby ensuring that they anticipated emission reductions from those provisions are achieved in practice. For these reasons, this alternative was rejected.

C. ALTERNATIVE 3 – Performance-based Standard

Staff considered a performance-standard based alternative for the proposed regulation. Specifically, staff considered a performance-based mandate to regulated entities to reduce the vented and fugitive emissions from regulated sources, as of a date certain, by an amount commensurate with the expected reductions the proposed regulation is expected to produce. Staff rejected this alternative for several reasons, but worked to incorporate flexibilities into the proposed regulation where possible to support legislative direction to avoid prescriptive regulations where possible.

Reasons for rejecting a wholesale performance standard alternative include the following points. This proposed regulation is designed to reduce venting and fugitive emissions from the sector. These emissions are, by their nature, difficult to quantify in many cases, and come from a wide range of potential sources. A flat reduction mandate would be very difficult to enforce without more accurate baseline data on current emissions from these sources, at the facility and component level, than is now available – it is, in other words, far more effective to enforce a requirement to replace a certain piece of equipment, or follow a particular LDAR procedure, than a performance-based reduction requirement from an uncertain baseline. To ensure reductions occur, therefore, staff focused on providing uniform, clear standards for equipment and processes that could reliably be measured, implemented, and enforced. Further, because emission controls focusing solely on methane reduction could have contributed to criteria pollutant emissions if poorly implemented, or failed to secure maximum co-benefits of criteria and toxic pollutants, it was important to specify particular implementation requirements to produce better results on this metric as well.

But though staff rejected a performance standard alternative as a complete option, staff made significant efforts to provide options within the rule's directive framework to provide compliance flexibilities. For instance, regulated entities have several options as to how to implement vapor control device provisions, to conduct LDAR inspections, and to address equipment replacement or retrofit decisions. These embedded options within the proposed regulation help reduce compliance burdens, thereby fulfilling the legislative intent driving consideration of performance-based alternatives, while ensuring that emission reductions happen in an enforceable and environmentally appropriate manner.

D. ALTERNATIVE 4 - Emission Reduction Provision

Staff also considered including an emission reduction provision that would require operators to mitigate climate impacts of large methane leaks. In evaluating whether an emission reduction provision would be appropriate, staff considered several options, including increased penalties for operators of facilities where the leak occurred and an emission reduction plan providing ton-for-ton reductions or stricter monitoring requirements. Staff concluded that stiffer monitoring requirements were the most appropriate. Increased penalties were not an effective option since all prohibited leaks violate the proposed regulation and thus every violation is potentially subject to the maximum penalties statutorily allowed. A plan for reductions was deemed inappropriate at this time, for the following reasons: first, developing generally applicable requirements for such a plan – though somewhat specified in the mitigation plan developed for the Aliso Canyon leak – is a difficult regulatory task when generalized to any potential facility, and so would likely delay the regulation and associated methane reductions. Furthermore, ARB has considerable authority to drive appropriate mitigation via its existing enforcement authorities and settlement authority. Therefore, rigorous monitoring provisions, rigorously enforced, were deemed appropriate for this proposed regulation. ARB will continue to consider the issue, however, and may revisit this decision in future rulemakings.

IV. FUNDING, IMPLEMENTATION, PERMITTING AND ENFORCEMENT

The proposed regulation's enforcement and implementation provisions recognize that California's local air districts already play an important role in regulating the oil and gas sector, and are interested in building on their efforts. The provisions make clear that ARB can directly enforce the proposed regulation, but also offer paths for local air districts to integrate its requirements into their existing programs to support efficient and effective enforcement.

A. FUNDING FOR IMPLEMENTING AND ENFORCING ARB'S PROPOSED OIL AND GAS REGULATION

ARB's proposed regulation can be implemented and enforced by both ARB and the districts. ARB staff assumes most local air districts will choose to take the lead in implementing and enforcing the regulation, with ARB playing a backstop role, and it is our preference for the local air districts to do so. However, ARB will take a lead role in districts that choose not to. The local air districts are more familiar with operators, conduct inspections nearby or at the same sites, and in many instances have been regulating such sources for decades. This is why the regulation provides for the local districts to enter into MOUs with ARB in order to define implementation and enforcement responsibilities, as well as for information sharing. The regulation also allows for districts to incorporate this regulation into their local rules. To ensure uniform enforcement, however, districts may not waive or reduce the stringency of the state rules, which remain state law, enforceable as necessary by ARB.

To aid enforcement, operators must register their facilities with ARB (unless the district takes on this task via MOU) and update relevant permits for permitted facilities. Permit updates can occur on whatever frequency now in use at a district; registration with ARB (or the district) is required by January 1, 2018.

Implementing and enforcing this regulation does not come without costs. Local air districts have the legal authority to raise fees paid by the regulated community to support additional programs such as this regulation, which will help to address these costs, but likely need board approval, which is uncertain. The rule also makes clear that districts may retain penalties secured from rule enforcement. ARB continues to explore opportunities to further assist the air districts.

ARB staff, with district input, estimate that the regulation will require on the order of 5-6 PYs to implement depending on the mix of district and ARB implementation. The costs are going to be higher with ARB enforcement than with district enforcement due to the need to travel, train new staff, and set-up programs including a registration program. The individual district cost estimates range from amounts some districts feel could be absorbed by them without additional funding, to over $300,000 per year in recurring costs and almost $1,000,000 in one-time costs, primarily for permitting. Even if the districts decide to implement and enforce this regulation, there is an annual cost for ARB to manage the reporting requirements in the regulation.

B. PERMITTING AND ENFORCEMENT

The proposed regulation addresses enforcement, permitting, and registration requirements for covered equipment and facilities in several ways:

- Operators with equipment and facilities that are already covered by local air district permitting programs must include the proposed regulation requirements as part of their submission, ensuring compliance with the proposed regulation. This submission will aid enforcement by ensuring that applicable requirements are gathered in operating and construction permits, but limits local air district workload because it does not require that any new permits be issued to otherwise unpermitted facilities or equipment. In addition, permits can updated upon scheduled renewal timelines, to avoid unduly increasing district workload. New covered equipment and facilities (including wells) must include this in their submission at the time they are permitted.

- All equipment and facilities covered by this proposed regulation would also be required, by January 1, 2019, to be registered with ARB, to ensure that ARB enforcement personnel have the information necessary to effectively enforce the regulation. However, if the local air district is also collecting this information, and has entered into an MOU with ARB to share the information with ARB, then this requirement may not apply, depending on the MOU details.

In sum, the proposed regulation is designed so that its requirements can be folded into existing permitting programs, where they exist, and to ensure that critical enforcement and compliance information reaches ARB, with minimum duplication of local air district efforts. Local air districts are free to expand or establish permitting or registration programs to support enforcement, but are not required to do so.

ARB anticipates working closely with the local air districts to support implementation and enforcement. The proposed regulation thus contains several provisions to support further ARB/air district cooperation on enforcement and implementation. It makes clear, first, that both ARB and local air districts may enforce and inspect to ensure compliance. ARB anticipates entering into MOUs with interested local air districts to ensure that these shared responsibilities are undertaken in a coordinated way. To further support local air districts in their efforts, the proposed regulation also provides that districts may incorporate the terms of the regulations into their local rule, that owners and operators must be subject to fee increases imposed by air districts to implement the proposed regulation, and that local air districts may retain penalties they collect enforcing the regulation.

To support statewide uniformity and rigorous enforcement, the proposed regulation is clear that no local air district may implement or enforce it in ways that reduce its stringency; similarly, local air district decisions, and permitting and registration decisions, do not in any way waive or limit ARB's own enforcement authority. Conversely, the proposed regulation is also clear that it does not preempt any local air district requirements that are more stringent, or substitute for compliance any applicable federal requirements.

Finally, the proposed regulation defines potential violations to provide clarity. Individual violations for which enforcement consequences may result include: (1) failure to comply with its requirements with regard to each individual piece of covered equipment, (2) each day or portion thereof out of compliance, (3) each metric ton of methane emitted in violation, (4) failure to submit any required report and each day or portion thereof the report is late, (5) failure to retain and failure to produce any record required by the regulation, (6) falsifying any information or record, and (7) producing inaccurate records or information.

V. TECHNICAL ASSESSMENT

A. DEVELOPMENT OF METHANE EMISSION STANDARDS

In developing the proposed regulation, Staff analyzed the impact of applying control measures to the different components affected by the regulation's provisions.

1. Crude Oil and Produced Water Separator and Tank Systems

Separator and tank systems are used to separate and store crude oil, condensate, and produced water. Based on ARB site visits to production facilities and conversations with industry, Staff identified several types of separator and tank system configurations. In crude oil production, the most common system consists of a separator, which allows emulsion to gravimetrically separate, and two tanks, one of which is used to hold the separated crude oil and one which is used to hold the produced water. There may be further oil tanks and produced water tanks downstream of these first two for further separation and treatment of the oil and produced water. However, for purposes of the proposed regulation, "separator and tank system" means the first separator in a crude oil or natural gas production system and only the tanks directly connected to the separator, which typically is no more than two – one for oil and one for produced water.

In dry natural gas production, the most common system consists of a heated separator used to heat the gas to remove liquids, and a single tank used to store produced water and small amounts of condensate, which is typically a mixture of very light hydrocarbons.

Each of the system configurations vary slightly due to factors such as the number of wells in the system, type of oil produced, and the amount of gas entrained in the crude oil or produced water.

Staff evaluated emissions from separator and tank systems based on the results of flash analysis testing. Emissions from flashing are primarily a result of depressurizing liquids from underground reservoir pressure to atmospheric pressure at the tanks. Staff used test data to derive average emission factors for crude oil and produced water, and then applied the factors to counts of separators and tanks and to oil and produced water throughputs, both obtained from the ARB Oil and Gas Industry Survey, to estimate annual methane emissions[43]. The results of the analysis and test data are provided in Appendix D.

The flash emission test data show that methane is emitted in varying quantities from each well or group of wells that serve each separator and tank system. The amount of methane emitted is a function of the percentage of

[43] See footnote 41. ARB. 2013. Oil and Gas Survey. _ARB 2007 Oil and Gas Industry Survey Results

methane contained in the gas, the volume of gas entrained in the liquid (the Gas Oil Ratio or the Gas Water Ratio), and the total oil and water throughput. This means that emissions can be different for each separator and tank system. As shown in the data in Appendix D, both heavy oil and light oil contain methane and may have similar volumes of gas entrained in the liquid. In some case, the only difference in methane emissions is due to the oil and water throughput.

a) Limited Throughput Exemption

Staff is proposing a limited exemption from flash analysis testing and vapor collection system requirements for small producers of oil and natural gas. The proposed exemption is based on an analysis of the flash test data as outlined in Appendix D to determine if there are production levels below which no systems are expected to exceed the proposed methane standard. The analysis shows that a separation and tank system will not exceed the proposed standard if both the crude oil production is below 50 barrels per day and the produced water production is below 200 barrels per day. This exemption applies to both crude oil and natural gas separator and tank systems. Owners or operators with systems meeting both of these requirements will not need to conduct flash analysis testing or control a separator and tank system with the use of a vapor collection system. ARB Staff estimates this will exempt approximately 1,500 smaller separator and tank systems from the proposed regulation requirements, resulting in lower costs for smaller producers without an expected impact on emission reductions.

b) Methane Standard

To develop the proposed emission standard, Staff analyzed impacts for a range of methane standards between 0 and 40 $MTCH_4$/Year for uncontrolled separator and tank systems. The proposed 10 $MTCH_4$/Year standard was chosen to achieve approximately 90% annual methane. Standards of 0 or 5 $MTCH_4$/Year were also considered, although those standards would have required vapor controls on significantly more systems while achieving only limited additional methane reductions. The results of the analysis are shown below in Table 7.

Table 7: Impact of Different Annual Methane Standards on Uncontrolled Systems[44]

	O&G System Threshold								
Category	**0 MT**	**5 MT**	**10 MT**	**15 MT**	**20 MT**	**25 MT**	**30 MT**	**35 MT**	**40 MT**
# of Systems Controlled	1,072	38	29	29	26	7	5	4	4
# of Water Tanks Controlled	1,432	303	294	289	281	252	224	168	99
System CH_4 Emission Reductions (MT)	1,217	929	871	871	821	408	350	316	316
Water Tank CH_4 Emission Reductions (MT)	8,132	7,445	7,424	7,390	7,344	7,116	6,744	5,897	4,631
Total CH_4 Emission Reductions (MT)	9,349	8,374	8,295	8,261	8,165	7,524	7,094	6,213	4,947
% of Total Emissions Captured	100.00%	90%	89%	88%	87%	80%	76%	66%	53%

While evaluating different methane standards, Staff also considered the US EPA New Source Performance Standards (NSPS) Subpart OOOO[45] for new or modified tank systems used at crude oil and natural gas production facilities. The NSPS sets an emissions limit of 6 tons of VOC per year for new or modified systems to require vapor recovery. This analysis was conducted to ensure that the proposed methane standard would be at least as stringent as the standard required by EPA. As described in Appendix D, the analysis shows that 6 tons per year of VOC is equivalent to approximately 36 metric tons per year of methane, which means that the proposed methane standard is more stringent than the current US EPA NSPS as it relates to VOCs. Therefore, the proposed methane standard will not result in emissions that exceed the current US EPA NSPS requirements and will provide significant reductions.

2. Circulation Tanks for Well Stimulation Treatments

Well stimulation treatments (WSTs) are performed on crude oil or natural gas wells to increase the production of gas or fluids. The different types of well stimulation treatments used at crude oil and natural gas production facilities

[44] Does not include emissions from tanks currently controlled under district rules.
[45] U. S. EPA. 2012. 77 FR 49542 Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, August 16, 2012.

include hydraulic fracturing, acid fracturing, and acid matrix stimulation. A WST is performed after a drilling operation has been completed, but before the well is put into final production. After a WST has been completed, the surface equipment used to conduct the operation is removed from the well pad and replaced with a circulation tank (see Figure 8) and other support equipment to remove drilling plugs and excess sand from the wellbore. During the circulation process, water is injected into the wellbore where it mixes with other hydrocarbon liquids found in the reservoir. The sand, contained within the water and hydrocarbon mixture, is then forced back up to the surface where it is transported to the circulation tank to remove the sand from the liquid mixture. This process is conducted to prevent sand from entering the separator and tank system where it can clog or damage equipment. Staff visited several different WST operations that used a circulation tank to circulate sand from a wellbore. In all cases, the tanks were open to the atmosphere. This allows methane to vent to the atmosphere during the circulation process.

Staff initially relied on US EPA estimates for emissions from hydraulically fractured oil wells[46]; however, industry conducted additional testing on wells located in California[47]. Although the industry testing is limited, Staff believes it is more representative of California data since WST is very different in other parts of the country. Due to the limited number of tests, Staff chose the upper limit of the range for the estimates. The data did not include information on other constituents in the vapor coming from the tanks other than methane. However, since the well stimulation process uses a variety of chemicals, there is potential for reductions in other pollutants such as toxic air contaminants.[48] A recent meta-analysis showed 87 percent of studies on unconventional natural gas development indicated increased air emissions compared to conventional natural gas development[49]. For this reason, and due to the fact that both the US EPA and California industry studies show that uncontrolled emissions of methane are associated with hydraulically fractured oil and gas wells, Staff is proposing emissions controls for all circulation tanks used in conjunction with well stimulation treatments.

During the development of the proposed regulation, Staff received feedback from industry[50] indicating that it may be difficult to collect small volumes of natural gas from some hydraulically fractured oil wells, or that although the

[46] U. S. EPA. 2014. Oil and Natural Gas Sector Hydraulically Fractured Oil Well Completions and Associated Gas during Ongoing Production.
[47] WSPA. 2015. Recirculation Tank Emissions Testing. October 2015.
[48] CCST. 2015. An Independent Scientific Assessment of Well Stimulation in California Volume I, Well Stimulation Technologies and their Past, Present, and Potential Future Use in California. Sacramento, CA
[49] Hays J., Shonkoff SBC. 2016. Toward an Understanding of the Environmental and Public Health Impacts of Unconventional Natural Gas Development: A Categorical Assessment of the Peer-Reviewed Scientific Literature, 2009-2015.
[50] WSPA. 2016. Meetings, Attachment 2. http://www.arb.ca.gov/cc/oil-gas/meetings/WSPA_attachment2_03042016.pdf

gas may be able to be collected, it may not be feasible to inject the gas into an existing vapor collection system. Staff contacted one manufacturer of circulation tanks to inquire about using their equipment to recover both small and large quantities of natural gas from circulated liquids. Through subsequent discussion, the manufacturer reported that their equipment is commonly used in other states outside of California for collecting gas from wells that are subject to US EPA NSPS requirements, and that their equipment can be used to collect any volume of natural gas liquids, including low volumes as used in circulation tanks[51].

Additional discussions with industry suggested that even if gas is collected from circulation tanks, it would be difficult to route the gas to an existing vapor collection system and that the gas may be of unsuitable quality for use in on-site equipment. Staff contacted one manufacturer of Low-NOx incinerators to determine if such a device could be used in this type of application[52] [53]. The manufacture reported that their devices are used for destroying low quality waste gas, and for situations where only a small amount of gas is collected, they may be able to temporarily store gas in what is called a “bladder” until a volume is large enough volume of gas is collected for incineration.

Based on initial discussions with industry and equipment manufacturers, Staff is proposing that facilities using circulation tanks in conjunction with WSTs develop a best management practices plan to reduce emissions from the tanks and provide ARB with the results of a technical demonstration of vapor control equipment by the date specified in the proposed regulation. This will provide time for industry and equipment manufacturers to work together to develop and test all necessary equipment, and help to ensure that industry is taking steps to reduce emissions while the equipment is being designed and tested.

For the purposes of estimating costs and emissions associated with controlling circulation tank emissions, Staff relied on cost estimates provided by manufactures of Low-NOx incinerators and costs to install a vapor collection system as described in Appendix B. To estimate the number of tanks that would be subject to the vapor control requirements, Staff estimated that 6 circulation tanks would be subject to the proposed requirements. This estimate is based the assumptions that only a limited number of circulation tanks are used in California. In practice, circulation tanks are portable and frequently moved from one job site to another, and the duration of a circulation job typically lasts no more than 48 hours. The calculations used to estimate the costs and emissions can found in Appendix B.

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[51] SandX. 2015. Phone conversation.
[52] Tim Egan. 2015. Email from Timothy Egan of Aeron to Joe Fischer of ARB. July 2.
[53] Aeron. 2015. Phone conversations.

3. Vapor Collection Systems and Control Devices

Vapor collection systems are used to control emissions for separator and tank systems, circulation tanks, and other types of equipment. The systems are used to collect and route vapors to equipment for use as a fuel source or underground injection, or to send the vapors to a control device that may thermally or non-thermally destroy the collected vapors. The collection systems are typically comprised of vapor collection piping and a compressor, although some systems operate without a compressor by using natural gas pressure.

Currently, vapor collection systems are used at crude oil and natural gas facilities for controlling VOC emissions from pressure vessels, tanks, separators, and other types of equipment such as natural gas compressors. After vapor is collected, it must be controlled with 95% efficiency. This level was chosen to align with the U.S. EPA NSPS requirements. The vapors are often sent to a sales gas or fuel gas system, but they may also be re-injected into an injection well or combusted with the use of a vapor control device. Vapor control devices, such as a flare or incinerator, are used to destroy collected vapors. However, destroying vapors with the use of these devices can also result in the formation of nitrogen oxides or NO_x emissions, which also contribute to the formation of ozone and particulate matter[54].

To develop the proposed vapor control device standards, Staff considered NO_x emission impacts in regions classified as nonattainment for federal and State ambient air quality standards. Staff is concerned with NO_x because it is an ozone precursor, and creating more of it in ozone impacted areas would have a negative effect on the air quality in those regions. These nonattainment areas are California air basins described in the Environmental Analysis, Appendix C to this document. Staff focused on designing methane emission controls that would complement and avoid interfering with efforts to address these important criteria pollutants, while protecting communities (including low-income and disadvantaged communities) living in these areas. Staff is proposing a systematic approach for handling any newly collected vapors, which results in reduced NOx emission from business as usual.

The proposal is designed to take a tiered approach with regard to collecting and disposing of methane vapors. The first tier of the proposal requires any newly collected vapors to be directed to an existing sales gas system, fuel gas system (where they are combusted as fuel in equipment), or sent to an existing gas disposal well for underground injection. This systematic approach to handling newly collected methane vapors is designed to use existing systems that have no impact on NO_x, since even the newly collected vapors used in a fuel gas system will displace natural gas that would have been purchased.

[54] U. S. EPA. 1999. Nitrogen Oxides (NOx), Why and How They Are Controlled.

If the facility does not have these options, the second tier is to use a new non-combustion vapor control device. During the regulatory development process, Staff contacted one non-combustion technology manufacturer that uses this type of equipment to reduce VOC emissions to determine if the technology could be used in oil and gas applications[55]. This type of technology rapidly cools and condenses vapors into a liquid. The manufacturer reported that condensing gaseous carbon dioxide along with methane can cause equipment problems and is not currently feasible. However, Staff has included an option to use a non-combustion technology if they become feasible in the future.

If the facility cannot use an existing sales gas, fuel gas, or injection system, or a non-combustion vapor control device, the facility can consider a newly installed or existing vapor control device. A new vapor control device must meet the proposed NO_x standard of 15 ppmv and must not use supplemental fuel gas to operate, aside from gas required to run a pilot. Table 8 compares average values of NO_x emissions from different types of combustion equipment. As shown, a low- NO_x incinerator and microturbine provide the lowest NOx emission rates compared to other types of combustion equipment, including regular flares and rich burn internal combustion engines.

If a facility has newly collected vapors and an existing flare, and needs to use a combustion control device due to this proposed regulation, then the facility will have to replace an existing higher-NO_x flare with a low-NO_x incinerator or other device that meets the 15 ppmv NO_x standard. As shown in Appendix D, replacing existing flares with low-NO_x incinerators will more than make up for the resulting new NO_x emissions from the combustion of newly collected vapors, resulting in a NO_x benefit of approximately 1.6 tons per year of NO_x.

Table 8: NO_x Emission Comparison of Equipment

Equipment Type	**NO_x Emissions** (lb/MMBtu Input)
Rich Burn IC Engine	0.170 [56]
Flare	0.068 [57]
NG Turbine	0.040 [18]
Low-NO_x Incinerator	0.018 [58]
Microturbine	0.015 [18]

[55] Air Products and Chemicals Inc. 2015. Phone conversation.
[56] U. S. EPA, Combined Heat and Power Partnership. 2015. Catalog of CHP Technologies. Section 1. Introduction. March.
[57] U. S. EPA. 2015. AP 42, Fifth Edition, Volume I Chapter 13: Miscellaneous Sources. Section 13.5 Industrial Flares. https://www3.epa.gov/ttnchie1/ap42/ch13/
[58] Aeron. 2015. Certified Ultra Low Emissions Burner, Sheets CEB 50 through CEB 1200. http://www.aereon.com/enclosed-combustion-systems/certified-ultra-low-emissions-burner-ceb

4. Reciprocating Natural Gas Compressors

Reciprocating compressors are used to compress natural gas by using a piston driven by crankshaft, connected to an engine or electric motor. Rod packing systems are the mechanism used to create a seal around a moving crankshaft, to contain the gas inside of the compressor. Due to the design of these systems, a rod packing or seal may leak a small amount of natural gas during normal operation, and have the potential to vent large amounts of gas if the rod packing or seal becomes damaged or wears out.

In order to develop the proposed emissions standard for reciprocating compressors, Staff reviewed the most current local air district rules for compressors, (see LDAR section below), the US EPA NSPS, information provided by rod packing manufacturers, and owners and operators of reciprocating compressors.

The current US EPA NSPS requires new or modified compressors used at gathering and boosting stations and natural gas processing plants to replace rod packing systems within 26,000 hours or 36 months of operation, regardless of the condition of the rod packing[59]. There are no other requirements for compressors installed at the other types of facilities. ARB Staff reviewed current local air district rules for requirements pertaining to natural gas compressors. They found that some compressors installed within major oil and gas producing regions are subject to regular leak inspection requirements over and above the NSPS standards. These requirements are included within the local air district leak detection and repair programs and require owners and operators to measure concentration from the vent area around the rod packing or seal and other compressor components on a regular basis.

In addition to evaluating the current federal and local requirements, ARB Staff also contacted a manufacturer of reciprocating compressors to gather information and manufacturer guidelines for replacing faulty or defective rod packing systems. The guidelines provided below, are described in terms of a natural gas flow rate of emissions from the vent near the piston rod-packing on the reciprocating compressor. Table 9 identifies the manufacturer's recommended guidelines for repairing or replacing rod packing systems. These guidelines apply to one compressor manufacturer that produces compressors for use at natural gas transmission and underground storage facilities where the compressor uses a driver engine or motor with greater than 250 rated horsepower.

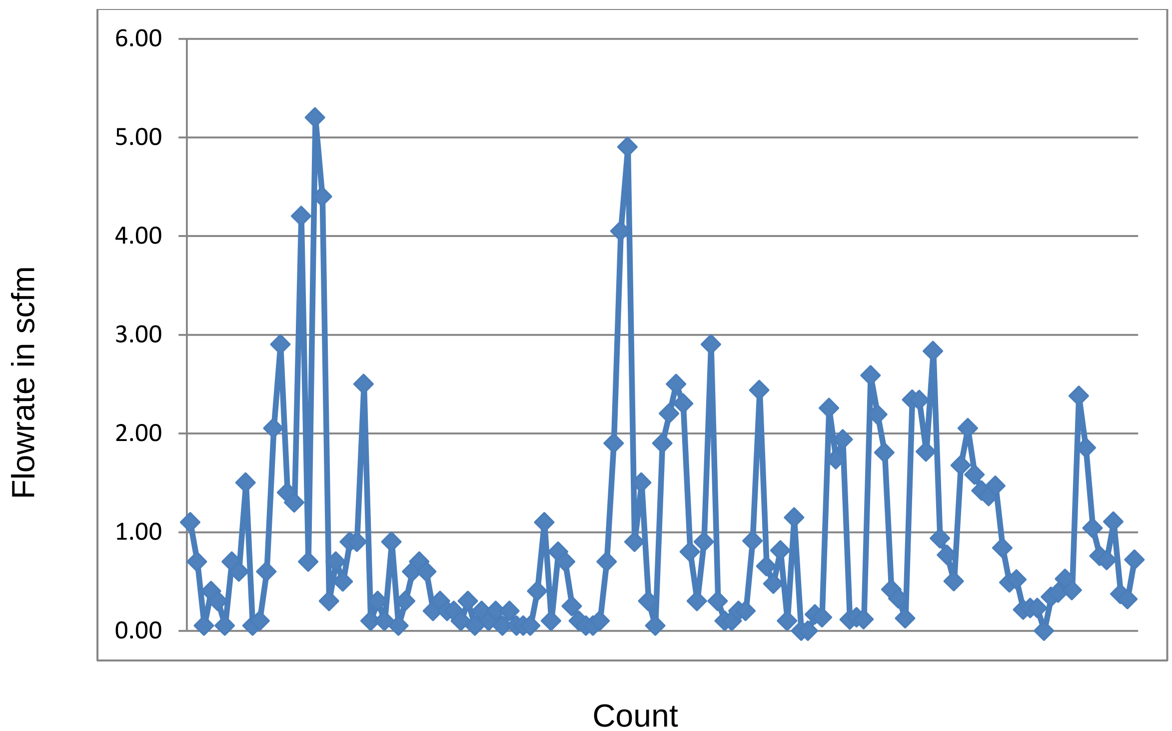
[59] U.S. EPA. 2012. 77 FR 49542 Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, August 16, 2012

Table 9: Manufacturer Rod Packing Guidelines[60].

Condition	**Rod Packing Flow Rate** measured in standard cubic feet per minute (scfm)	**Rod Packing Flow Rate** measured in standard cubic feet per hour (scfh)
Excellent	0.02	1.2
Good	0.05	3.0
Normal	0.10	6.0
Fair	0.50	30.0
Poor (Alarm)	2.00	120.0
Very bad	3.00	180.0
Dangerous	4.00	240.0
Failure	100.00	6000.0

Staff also used natural gas emission flow rate data provided by industry. The industry provided data included measurements from 55 reciprocating compressors taken over a four year period. According to the data, about 14% of the measurements indicated a leak rate of over 2 scfm per cylinder. Figure 10 below depicts the industry provided flow rate measurements.

Figure 10: Measured Rod Packing Flow Rate (scfm)



Most of the measurements in Figure 10 are below 2 standard cubic feet per minute (scfm), or 120 scfh, which is below the manufacturer's "poor" guideline

[60] Dresser-Rand. 2014. Email from Matt Gilbert of Dresser Rand to Christian Hurley of ARB. December 17, 2014.

rating. However, several were measured above 2 scfm, and would be considered dangerous or as a rod packing failure according to the manufacturer's guidelines shown in Table 9.

Using the manufacturer's and industry data, Staff is proposing a 2 scfm standard for rod packing emissions from compressors used at natural gas transmission compressor stations, underground storage facilities, gathering and boosting stations, and processing plants. This standard was designed to correspond with the manufacturer's recommended guidelines for heavy duty compressors used at these types of facilities, regardless of the amount of time the compressor has been in use. Because many of these compressors use elevated vents stacks, ARB Staff also proposes that each compressor is outfitted with an access port installed at ground level to ensure that both the operators and inspectors can make regular flow rate measurements without specialized equipment. In addition, these compressors are subject to the LDAR requirement for all components other than the rod packing. Any newly installed or modified compressor must still comply with the NSPS as well as the proposed regulation.

Staff believes that the NSPS standards do not conflict with ARB's proposed emissions standards. In the event that a rod packing is measured in accordance with the proposed testing requirements prior to the EPA NSPS timeframe, the rod packing may not require repair or replacement, which does not interfere with the NSPS standards. However, in the event that a rod packing is measured above the proposed emissions standards, the rod packing would require repair or replacement sooner than the NSPS timeframe, which will result in fewer methane emissions. In addition, the NSPS only applies to compressors found at gathering and boosting stations and natural gas processing plants, whereas this proposed regulation's rod packing standard also applies to compressors at underground natural gas storage facilities and transmission compressor stations.

The remaining compressors identified in the ARB survey are located at oil and natural gas production facilities. ARB proposes that compressors used at production facilities undergo LDAR testing to check the rod packing or seal in order to provide for a simple leak concentration measurement. ARB is also proposing that all other components on production compressors be subject to LDAR. Staff considered using the same flow rate measurement standard as proposed for compressors used at other types of facilities, as well as the simpler LDAR test method and emission standard. During site visits, Staff found that nearly all production facility compressors are uncovered and can be reached from ground level. Further, many of the production facility compressors are already subject to local air district LDAR requirements, which is an effective, easier test method to perform. In order to integrate with local air district programs and provide a simpler form of testing for the majority of compressors located in California, staff is proposing to use the Method 21 test method (detailed further in the LDAR section) combined with a 30-day repair timeframe for a rod packing or seal that is measured above the minimum LDAR leak threshold. The 30 calendar day repair timeframe is intended to provide time for the owner or operator to remove the compressor from service and make the necessary repairs.

3. Centrifugal Natural Gas Compressors

Centrifugal compressors use a rotating disk or impeller to pressurize natural gas for use in a transmission pipeline or underground storage applications. Similar to reciprocating compressors, centrifugal compressors also use a mechanism, referred to as either a wet seal or a dry seal, to create a seal around a moving crankshaft, which contains the gas inside of the compressor. Wet seals use pressurized oil circulated around the moving shaft to form a barrier and contain the natural gas inside of the compressor. Unlike wet seals, dry seals do not use high pressure oil to create the sealing barrier. Instead, dry seals use a very tight tolerance fit to contain the gas inside of the compressor. Methane emissions from wet seals are higher than the emissions from dry seals because normal operation causes natural gas to become entrained into the seal oil, which is circulated through the oil pump system, and emitted.

To develop the proposed wet seal emissions standard, Staff reviewed the current NSPS[61], the EPA Natural Gas STAR recommended technologies and practices[62], and data collected as part of the ARB survey[63]. Staff also conducted several site visits to natural gas transmission and underground storage facilities and visited a centrifugal compressor manufacturing facility to verify wet seal and dry emissions rates, and learn about compressors and common maintenance practices, including retrofitting.

Current NSPS requirements state that all new or modified compressors installed at oil and gas production facilities must control 95% of the wet seal emissions. There are no NSPS requirements for compressors installed at transmission compressor stations or underground storage facilities. Staff contacted each of the facilities reporting centrifugal compressors in the 2007 ARB survey. Staff confirmed that there is only one uncontrolled wet seal centrifugal natural gas compressor currently operating in California. The compressor is not subject to EPA NSPS requirements.

To develop the proposed emission standard, Staff referred to the US EPA Natural Gas STAR recommended technologies and practices. The Gas STAR program is a voluntary partnership that encourages oil and natural gas companies to adopt cost-effective emission reduction technologies. According to the Gas STAR data, wet seals are estimated to emit 50 scfm

[61] U. S. EPA. 2012. 77 FR 49542 Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, August 16, 2012.
[62] U. S. EPA. 2014. Natural Gas Star. Wet Seal Degassing Recovery System for Centrifugal Compressors.
[63] See footnote 41.

(3000 scfh) per seal while dry seals emit 3 scfm (180 scfh) per seal. Because both the wet seal and dry seal emission estimates are provided in terms of flow rate, Staff concluded that measuring the wet seal emission flow rate is feasible, as long as the operator or inspector has access to the wet seal vent stack for making measurements.

Staff developed the 3 scfm emission standard because this is the equivalent of an average dry seal emission rate and similar to a 95% vapor control for the average wet seal emission rate. Staff also proposes that an access port for making flow rate measurement be installed at ground level.

Two alternatives means to meet this standard are also proposed. One option is for the operator to control the emissions from wet seals with at least 95% control efficiency using a vapor collection system. It is identical to the NSPS for centrifugal compressors installed at production facilities. The second alternative allows the operator to replace the wet seals with dry seals by January 1, 2020. This provides additional time for the operator to modify California's only wet-seal reciprocating compressor due to the high cost of replacing a wet seal compressor with a dry seal compressor, if controlling the emissions with the use of a vapor collection system is not possible.

4. Natural Gas Powered Pneumatic Devices and Pumps

Pneumatic devices are used for maintaining a process at an oil or natural gas facility such as liquid level, pressure, or temperature. While pneumatic devices are commonly used at crude oil production facilities, most devices use compressed air or electricity to operate and therefore do not vent natural gas or methane emissions. However, gas powered pneumatic devices are commonly found at natural gas production and midstream facilities such as natural gas transmission compressor stations or underground storage facilities where natural gas is readily available. These devices use pressurized natural gas to operate and can be classified into three primary types;

- Continuous bleed devices vent natural gas to the atmosphere on a continuous basis.
- Intermittent bleed devices also vent natural gas to the atmosphere but only do so when they control a process, or more specifically, when the actuators spin to open or close or control a process; and
- No bleed devices do not vent natural gas while idle or when they actuate.

a) Continuous Bleed Devices

Continuous bleed devices, as the name implies, are designed to continuously vent natural gas into the atmosphere in order to operate.

The devices are commonly referred to as either high bleed or low bleed depending on the volume of gas that is vented,

- o High Bleed devices vent more than 6 scfh;
- o Low Bleed devices are those that vent less than 6 scfh;

Due to advances in technology, the use of electronic control instrumentation has been increasing. These systems use small electrical motors to operate valves and therefore do not bleed natural gas into the atmosphere. Mechanical devices are another alternative to high bleed pneumatic devices that are widely used in the natural gas and petroleum industry. They operate using a combination of springs, levers, flow channels and hand wheels. However, use of the mechanical devices is limited because they need to be in close proximity to the process measurement[64].

Staff contacted one manufacturer of continuous bleed pneumatic devices to discuss retrofitting existing high bleed devices with electric or mechanical devices[65]. The manufacturer reported that they provide retrofit kits for a number of their units for converting the devices to use electricity, and they also supply retrofit kits to convert units to low bleed[66].

Staff also considered recently installed low bleed devices as several operators recently choose to change out high bleed devices with low bleed devices instead of installing metering in order to be compliant with ARB's Mandatory Reporting Regulation. Requiring these low bleed devices to be changed to no bleed devices would place a burden on facilities, but the amount of methane emissions reduced by replacing those previously installed low bleed devices is small when compared to the total methane emissions from continuous high bleed natural gas powered pneumatic devices.

Accordingly, Staff is proposing that continuous bleed pneumatic devices be converted to no bleed devices, except where high bleed devices have been recently changed out to low-bleed devices pursuant to ARB's Mandatory Reporting Regulation.

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[64]U.S. EPA. 2014. Options for Reducing Methane Emissions from Pneumatic Devices in The Natural Gas Industry.
[65] Emerson Process Management. 2015. Phone conversation.
[66] Emerson Process Management. 2016. Electro-Pneumatic Transducers. http://www2.emersonprocess.com/en-US/brands/fisher/FieldInstrumentation/valveaccessories/Electro-PneumaticTransducer/Pages/FisherElectro-PneumTrans.aspx

b) Intermittent Bleed Devices

Intermittent bleed devices vent natural gas only when they control a process, and the frequency of the controlling depends upon the size of the device and the particular operation. Since intermittent bleed devices are designed to prevent natural gas from venting while idle, Staff proposes for these devices to be subject to LDAR and should be tested while idle to ensure no unintended leakage. This ensures that industry, ARB, and local air district inspectors conduct consistent testing among all of the different devices.

c) Pneumatic Pumps

Pneumatic pumps, commonly referred to as "Kimray" pumps, are often found at natural gas production well sites and used in conjunction with glycol dehydrators. There are two types of gas powered pumps: piston and diaphragm. Both types have two major components, a driver side and a motive side, which operate in the same manner but with different reciprocating mechanisms. Pressurized gas provides energy to the driver side of the pump, which operates a piston or flexible diaphragm in order to draw liquid into the pump. The natural gas leaving the exhaust port of the pump is either directly discharged into the atmosphere or is recovered using a vapor collection system[67].

In contrast to gas powered pumps, electric motor driven pumps do not use pressurized gas to operate and therefore do not vent emissions to the atmosphere. Using electric pumps as an alternative to gas powered pumps provides significant benefits. First, electric powered pumps provide a financial return on the gas that is otherwise vented into the atmosphere. Second, worn O-rings in gas powered pumps can cause contamination of lean glycol in the dehydrator, reducing system efficiency and requiring an increase in the glycol circulation rate, compounding the methane emissions. Finally, replacing gas powered pumps often results in lower annual maintenance costs because the O-rings in gas powered pumps must be replaced when they begin to leak, typically every 3 to 6 months. The need for this replacement is eliminated when electric pumps are employed[68].

Staff has provided several options that owners or operators can use to comply with the proposed regulation standard of not venting gas, including replacing gas powered pumps with electric pumps, collecting the vented gas with the use of a vapor collection system, or using compressed air to operate. Staff performed the cost analysis assuming that all pumps would be replaced with electric powered

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[67] U. S. EPA. 2014: Oil and Natural Gas Sector Pneumatic Devices.
[68] U. S. EPA. 2006. Replacing Gas-Assisted Glycol Pumps with Electric Pumps.

pumps as described in Appendix B. However, it is possible that some owners or operators may use one of the other available options.

5. Liquids Unloading of Natural Gas Wells

Staff proposes to require that owners or operators of natural gas wells vented to the atmosphere for the purpose of liquids unloading, collect the vented gas using a vapor collection system; measure the volume of vented gas by direct measurement; or calculate the volume of vented gas. There are currently no rules that apply to the unloading of liquids from natural gas wells and the purpose of this provision is to gather data about liquids unloading activity in California. This data will inform ARB Staff, in modifying these rules for additional emission reductions.

6. Well Casing Vents

Staff is proposing that owners or operators of crude oil or natural gas wells with well casing vents that are open to atmosphere perform annual flow rate emissions testing of each casing vent and submit the results to ARB annually. The purpose of this provision is to gather equipment and emissions data which will inform ARB Staff if future emissions controls are necessary.

7. Natural Gas Underground Storage Facility Monitoring Requirements

A large natural gas leak was discovered at a natural gas storage facility in Southern California on October 23, 2015 (Aliso Canyon). Numerous initial attempts to stop the leak failed, and on January 6, 2016, Governor Brown issued a state of emergency. The leak was plugged on February 18, 2016. This event highlighted the need to require monitoring at all natural gas storage facilities. The Division of Oil and Gas and Geothermal Resources (DOGGR) responded by adopting an emergency regulation for gas storage facilities (Cal. Code Regs., tit. 14, s 1724.9, subd. (e)) that requires operators of storage facilities to submit an inspection and leak detection protocol to DOGGR for review and approval.[69] The protocol is required to include inspection of the wellhead, attached pipelines, and area within a 100 foot radius of the wellhead at least daily. The operator is required to select and use gas leak detection technology such as infrared imaging that takes into consideration detection limits, remote detection of difficult to access locations, response time, reproducibility, accuracy, data transfer capabilities, distance from source, background lighting conditions, geography, and meteorology. DOGGR staff is currently working with operators to finalize and approve leak detection protocol for each facility.

[69] DOGGR. 2016. Requirements for Underground Gas Storage Projects. Final Text of Emergency Regulations.

DOGGR anticipated including the leak detection protocol requirements in their final regulation expected to be adopted in early 2017. As DOGGR and ARB have agreed that the monitoring requirements are more appropriately located in ARB's Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities, staff has included them in the proposed regulation.

Storage facility monitoring requirements under the proposed regulation will replace the leak detection protocol under DOGGR's regulation. In developing the requirements, ARB staff was cognizant of investments facility operators may have made to acquire leak detection instruments and systems and to assure that they would qualify for use under the proposed regulation. The area around the wellhead to be included in leak screening has been expanded under the proposed regulation to 300 feet in response to the detection of leaking gas in this area at Aliso Canyon.[70]

The proposed regulation requires natural gas storage facility owners and operators to develop and submit to ARB a plan to provide continuous ambient air monitoring at the facility and to screen for surface leaks at least daily. Continuous air monitoring is included in response to community concern with exposure to pollutants that resulted from the leak at Aliso Canyon. To provide data transparency to the public, the monitoring system is required to be accessible remotely by the ARB and other state or local agencies specified by the ARB Executive Officer.

8. Leak Detection and Repair

The proposed leak detection and repair (LDAR) requirements are used to locate and measure leaks at facilities. Local air districts in the major oil producing regions of California currently implement LDAR programs at crude oil production facilities. These programs, as originally designed and intended, reduce emissions of VOC gases but do not cover components used in natural gas service including those found in dry natural gas production, underground storage, or transmission compressor facilities. This is because methane is not considered a major contributor to ground level ozone, so it has not been counted as a VOC. Using ARB's 2007 Survey data, ARB Staff estimates that current local air district programs cover about 80% of all components used at crude oil and natural gas facilities throughout California[71]. Implementing LDAR will be used to prevent the release of powerful greenhouse gas emissions found at these facilities. It could also reduce product losses, increase safety for workers, and decrease the exposure of the surrounding community. In the following sections Staff details the development of the three major provisions of ARB's proposed LDAR requirement.

[70] South Coast Air Quality Management District. 2016. SCAQMD/DOGGR Joint Inspection. http://www.aqmd.gov/home/regulations/compliance/aliso-canyon-update/air-sampling/scaqmd-doggr-joint-inspection
[71] See footnote 41.

a) Test Method Requirement

To develop the proposed LDAR requirement, Staff evaluated current local air district rules and the US EPA Method 21[72] test method, and Optical Gas Imaging (OGI) technologies. Each of the local air districts that currently have LDAR programs require Method 21 in combination with specified leak concentration thresholds[73] [74] [75] [76] [77]. The leak measurement is then used to determine the timeframe in which a facility must make repairs to fix the leaking component. Method 21 is the only test procedure currently in use by the local districts at oil and gas facilities. This method is favored because it has the ability to quantify leak concentrations. Quantifying the concentration of leaks gives air districts the ability to define leak thresholds and thereby specify repair timeframes, with the largest leaks having the shortest repair timeframe. This approach provides the districts with the ability to enforce the leak standards if measured concentrations exceed specified thresholds.

OGI is an alternative to Method 21 measurements, but is used to view leaks from various sources including hard-to-reach and unsafe locations. While traditional OGI cannot measure leak concentrations and there are no US EPA adopted test methods available for using these instruments, Staff discovered that there are new OGI technologies that are evolving and are being designed to quantify emissions. This technology is currently untested; however ARB is open to future testing for use of this new type of OGI measurement technology, including comparative testing with Method 21 instrumentation.

For this rulemaking, ARB proposes the use of Method 21 to implement a US EPA-approved test method along with a set of leak thresholds and repair timeframes that are similar to current local air districts. Both the local air districts and facility operators can use their existing instruments to implement the same or similar standards at facilities that are not currently subject to a LDAR program. Although Staff proposes

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[72] CFR. 2016. Method 21 - Determination of Volatile Organic Compound Leaks. http://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&tpl=/ecfrbrowse/Title40/40cfr60_main_02.tpl

[73] San Joaquin Valley Air Pollution Control District. 2011. Rule 4401: Steam-Enhanced Crude Oil Production Wells.

[74] San Joaquin Valley Air Pollution Control District. 2005. Rule 4409: Components at Light Crude Oil Production Facilities, Natural Gas Production Facilities, and Natural Gas Processing Facilities.

[75] Ventura County Air Pollution Control District. 1998. Rule 74.10: Components at Crude Oil and Natural Gas Production and Processing Facilities.

[76] Santa Barbara Air Pollution Control District. 1991. Rule 331: Fugitive Emissions Inspection and Maintenance.

[77] South Coast Air Quality Management District. 2009. Rule 1173: Control of Volatile Organic Compound Leaks and Releases From Components at Petroleum Facilities and Chemical Plants.

Method 21 as the required test method, the proposed regulation will not prohibit the use of OGI technologies. Some local air districts and oil and natural gas facilities currently use OGI as a means to perform leak screening surveys, with Method 21 used to determine compliance with the leak thresholds and repair timeframes. Staff believes the same type of work practice will continue with the adoption of the proposed LDAR program, and ARB encourages the use of alternative leak detection instruments including the use of OGI technologies. ARB has a contract nearing completion to compare different LDAR technologies and determine correlation equations, if feasible, but results are not currently available for evaluation.

b) Leak Threshold and Repair Times

This proposed rule includes requirements for leak thresholds and repair time periods for components at oil and natural gas facilities. Detected leaks must be repaired within a specific time period depending on the leak concentration, with larger leaks requiring the quickest repair times. Staff developed a phased in approach with higher concentration thresholds in the first two years. The final thresholds and repair times are as follows:

Table 10: Repair Time Periods on or after January 1, 2020

Leak Threshold	Repair Time Period
1,000-9,999 ppmv	14 calendar days
10,000-49,999 ppmv	5 calendar days
50,000 ppmv or greater	2 calendar days
Critical Components	Next shutdown or within 12 months

In the proposed regulation, 1,000 ppmv is the lowest leak threshold defined. Staff chose this threshold to be consistent with the majority of districts with oil and gas LDAR regulations. District regulations vary on the threshold but 1,000 ppmv is the most common across the districts. In addition, staff chose to lower the threshold from 10,000 ppmv after two years to 1,000 ppmv simply to ensure that more leaks are being detected. The thresholds and repair times assure that leaks are repaired once found and that the largest emitting sources are prioritized. The quickest leak repair time period is 2 calendar days for leaks measuring 50,000 ppmv or greater.

c) Leak Inspection Frequency

To develop the proposed leak inspection frequency, Staff reviewed existing LDAR programs currently in use by California local air districts, then contacted enforcement Staff and management at the Santa Barbara, Ventura, South Coast, and San Joaquin Valley air districts to further discuss the minimum inspection frequency requirements in detail. The districts require daily inspections for specific types of components that have the potential for substantial emissions, such as pressure relief valves. These inspections are audio or visual based and do not require instrument testing. Each district also has provisions for unmanned or remote facilities that allow operators to inspect those facilities on a less than daily basis. ARB believes these are appropriate and in line with recent findings that open tank hatches can be a significant source of methane.[78]

The Method 21 instrument-based inspection frequency is also similar among each of the different air districts. For example, in South Coast, Santa Barbara, Ventura, and the San Joaquin Valley (for gas and light crude oil), the minimum inspection frequency is quarterly for a minimum number of inspection quarters. If a facility meets a specified set of criteria, they may convert to annual inspections. The criteria for converting from a quarterly to annual inspection frequency is based upon the number of leaks found during each inspection period and does not prevent the district from conducting random leak inspections. At any time during a calendar year, the local district may enter a facility and conduct random leak inspections in order to determine if the facility is in compliance with district LDAR rules. If at any time a district discovers leaks that exceed the LDAR requirements, or finds leaks that may exceed a maximum leak threshold, the annual inspection frequency reverts to quarterly. This approach is similar to the approach currently used by several local air districts.

Quarterly LDAR achieves approximately a 60 percent reduction in methane emissions from leaking components, whereas annual LDAR achieves only about a 40 percent reduction.[79] In addition, quarterly inspections will result in more opportunities to detect “super-emitting” components, the source of the majority of component emissions, according to several studies.[80] [81] [82] [83] [84] [85]

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[78] ACS Publications. 2016. Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites. Environmental Science & Technology. Publication Date (Web): 05 Apr 2016.
[79] ICF International. 2014. Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries.
[80] See footnote 19.
[81] See footnote 21.
[82] See footnote 25.
[83] See footnote 26.

Based on the information gathered, ARB Staff proposes a quarterly instrument-based inspection frequency with an option for compliant facilities to convert to annual inspections after passing a minimum of five quarterly inspections. In addition, ARB's regulation will require a daily audio-visual inspection requirement for facilities that are visited on daily basis, and weekly audio-visual inspection requirement for unmanned or remote facilities. The audio-visual based inspections are required for all accessible pumps, compressors, and automatic pressure relief valves located at each facility. These requirements are designed to integrate with the proposed Method 21 test method, leak thresholds, and repair timeframes, and to integrate with existing local air district rules.

[84] See footnote 27.
[85] See footnote 28.

VI. JUSTIFICATION FOR ADOPTION OF REGULATIONS DIFFERENT FROM FEDERAL REGULATIONS CONTAINED IN THE CODE OF REGULATIONS

Oil and gas operations are also subject to the federal Clean Air Act, including its permitting requirements. They are subject to U.S. EPA performance standards for oil and gas operations. These regulations, 40 C.F.R. Part 60, Subpart OOOO (Quad O), limit emissions of volatile organic compounds from new equipment installed at crude oil and natural gas operations. Corresponding air toxics standards for certain pieces of oil and gas equipment are also codified in 40 C.F.R Part 63. In 2015, EPA committed to reduce methane emissions in the U.S. by 40 percent below 2012 levels by 2025 from the oil and gas sector. As part of this effort, EPA has proposed additional NSPS requirements for new and modified sources in the oil and gas sector and suggested Control Technology Guidance for existing sources in non-attainment areas. EPA finalized its rules in May 2016. On March 10, 2016, President Obama announced steps to reduce emissions from all existing oil and gas facilities but that process is in the information gathering stage. ARB staff anticipate that controls proposed in this regulation would aid in (and may suffice entirely for) compliance with any federal standards developed.

California has authority to set its own standards to reduce emissions further to meet federal and state ambient air quality standards and climate change requirements and goals, and to require additional and separate reporting. The proposed regulation addresses existing facilities and equipment where Quad O does not, and is more restrictive. The differing state requirements proposed are authorized by law (AB 32, as discussed above) and are necessary to achieve additional benefits for human health, public welfare, and the environment, and are justified by these benefits, as envisioned by authorizing legislation, as this section explains.

ARB’s proposed regulation covers more facilities in California compared to EPA’s NSPS, because it will apply to existing and new facilities, including offshore oil and natural gas production facilities. EPA’s New Source Performance Standards (NSPS) applies to onshore oil and gas facilities newly constructed, reconstructed, or modified after August 23, 2011 (or after September 2015, in certain cases to which the May 2016 final federal rule applies). The types of facilities subject to the NSPS, are natural gas well sites, oil well sites, production gathering and boosting stations, natural gas processing plants, and natural gas compressor stations (transmission and storage).

The Bureau of Land Management (BLM) has also recently proposed new regulations to reduce the waste of natural gas from venting, flaring, and leaks during oil and gas operations on federal and tribal lands. (43 CFR 3162 and 3179) These proposed regulations are consistent with EPA’s NSPS rules and would apply to sources not covered in those rules. ARB’s proposed regulation does not apply to tribal lands; it does apply to federal lands, in which case ARB may develop an MOU with BLM to coordinate enforcement.

In addition to direct federal regulations, many air districts with significant oil production have rules aimed to reduce $PM_{2.5}$ as well as NO_x and VOC emissions specifically from the oil and gas sector in order to meet federal ambient air quality requirements. The district rules do not cover methane specific sources and the proposed regulation generally addresses emissions from equipment and processes not already controlled by those existing district rules. ARB has used the district rules as a starting point, particularly for leak detection and repair, where districts have been implementing programs for decades.

ARB staff carefully reviewed existing and proposed regulations as this proposed regulation was developed. Because EPA's rule was finalized as this proposed regulation was being issued, review of modifications made to that rule during finalization is ongoing. However, because that rule covers only new sources, and follows the basic structure of EPA's proposal, it does not obviate the need for more rigorous, and far broader, source coverage in this proposed regulation. Indeed, EPA makes clear that its final rules in intended to complement state efforts, rather than supplant them. The proposal is designed to be as strong as, or stronger than, existing rules in other jurisdictions and in certain California air districts, and to extend strong elements of those rules. The proposal is also designed to integrate well with regulatory efforts for other aspects of the sector, as well as to provide a complementary basis for compliance with potential proposed federal rules.

VII. AIR QUALITY

A. OVERVIEW

This chapter describes the expected emissions, air quality, and health impacts associated with the proposed regulation. Furthermore, this chapter reports on the potential effects of the proposed regulation on environmental justice and local communities. The purpose of the proposed regulation is to establish GHG, primarily methane, emission standards for the oil and gas operations and facilities covered under the proposed regulation. Additionally, the Draft Environmental Analysis in Appendix C identifies the reduction of volatile organic compounds and toxic air contaminants as a co-benefit of the proposed control strategies.

1. Air Quality

ARB's Draft Environmental Analysis (Draft EA) in Appendix C, describes the long-term operations resulting from compliance with the proposed regulation. These operations could include the combustion of methane vapors as a management option for captured methane gas and increased vehicle use as a result of inspections, equipment replacement and repairs, and transporting compressed vapor. These compliance responses, if not properly constrained as they have been in the proposed regulation, have the potential to increase emissions from the pollutants for which national and state ambient air quality standards have been established.

The proposed regulation is designed to require the cleanest combustion devices, consequently reducing any potential additional air quality emission impacts to below significance in nonattainment areas and would not affect areas currently in attainment. Specifically, though some newly-collected vapors may be combusted, the proposed regulation requires that inefficient combustion devices already in use be replaced with cleaner devices before they can be used for compliance. The result of this design ensures that no significant emission increases would occur in nonattainment areas, and could result in a net reduction of emissions for some areas and pollutants.

Table 11 displays the estimated statewide GHG emission benefits from the proposed regulation by category. These benefits are described in further detail in Chapter 4.8 of the Draft EA, Appendix C. In addition to the benefits identified in Table 12, the proposed regulation would also provide a reduction in risk of large, catastrophic methane releases (similar to the events at Aliso Canyon) from the proposed enhanced monitoring at natural gas underground storage facilities.

Table 11: Estimated Statewide GHG Emission Reductions (MT CO_2e/year).*

Category	Reductions
Vapor collection on uncontrolled oil and water separators, tanks, and sumps with emissions above a set methane standard	538,000
Control of vapors from uncontrolled well stimulation circulation tanks	4,900
Leak Detection and Repair (LDAR) on components, such as valves, flanges, and connectors currently not covered by local air district rules	590,000
Inspection and repair requirements for reciprocating natural gas compressors	68,000
Vapor collection of centrifugal compressor wet seal vent gas, or replacement of higher emitting “wet seals” with lower emitting “dry seals”	3,500
Replacement of pneumatic pumps, and replacement or retrofitting of pneumatic devices under certain circumstances	319,000
TOTAL from proposed regulation	1,523,000

*Using 20 year GWP, AR4

Table 12 displays ARB’s estimated statewide emissions reductions of toxic air contaminants and criteria air pollutants from implementation of the proposed regulation. ARB’s detailed description on the emissions calculations is found in Appendix D of this ISOR. Generally, the emissions were calculated from a combination of emission factors, survey data, and other data provided by stakeholders based on likely compliance responses to each of the provisions in the proposed regulation. ARB’s detailed description of the air quality impacts of the proposed regulation is found in the Draft EA in Appendix C, Chapter 4.3 of this ISOR.

Reductions in emissions from vapor collection on uncontrolled oil and water separators, tanks, and sumps all occur in the San Joaquin Valley Air Basin, since ARB’s analysis showed that facilities in other oil and gas production regions would either not exceed the methane standard or already have vapor collection installed. As noted in Table 12, ARB estimates statewide NOx benefits of approximately 1.6 tons per year from vapor collection tanks, separators and sumps. This is a result of the design of the proposed regulation which requires the use of a complaint vapor control device (e.g., low-NO_x combustion device). However, ARB’s analysis of vehicle emissions associated with LDAR results in an estimated statewide increase in NOx of approximately 1.6 tons per year. Therefore the proposed regulation results in an estimated statewide net increase in NOx of less than 0.1 tons per year. A detailed description of these emissions can be found in the Draft EA.

Table 12: Estimated Statewide Emission Reductions of Toxic Air Contaminants and Criteria Air Pollutants (tons/year)

Category	Total Hydrocarbons	VOCs	Benzene	Toluene	Ethyl-Benzene	Xylenes	NOx
Vapor collection on uncontrolled oil and water separators, tanks, and sumps with emissions above a set methane standard[1]	10,458	1,362	23	11	1.7	8.5	1.6
Control of vapors from uncontrolled well stimulation circulation tanks	96	12	0.2	0.1	<0.1	<0.1	<0.1
Leak Detection and Repair (LDAR) on components, such as valves, flanges, and connectors currently not covered by local air district rules	9,698	1,264	22	10	1.5	7.9	(1.6)[2]
Inspection and repair requirements for reciprocating natural gas compressors	1,318	172	3.0	1.4	0.21	1.1	NA
Vapor collection of centrifugal compressor wet seal vent gas, or replacement of higher emitting “wet seals” with lower emitting “dry seals”	68	9	0.2	<0.1	<0.1	<0.1	NA
Replacement of pneumatic pumps, and replacement or retrofitting of pneumatic devices under certain circumstances	6,199	808	14	6.5	1.0	5.0	NA
TOTAL (benefits from proposed regulation)	27,837	3,627	62	29	4.6	23	(<0.1)

[1] All estimated emission reductions from this category are occurring in the San Joaquin Valley Air Basin.
[2] ARB estimates that increased LDAR will result in increased NOx from vehicle emissions by 1.6 tons/year.

In addition to the statewide emission benefit evaluation, ARB completed an emissions impacts analysis at the district level as part of the Draft EA in

Appendix C. ARB staff completed this analysis for the following districts: Bay Area AQMD, Butte County AQMD, Colusa County APCD, Feather River AQMD, Glenn County APCD, Monterey Bay Unified APCD, North Coast Unified AQMD, Santa Barbara County APCD, South Coast AQMD, SJVAPCD, Sacramento Metropolitan AQMD, Tehama County APCD, Ventura County APCD, and Yolo-Solano AQMD. ARB's analysis identified negligible emission impacts (less than 0.1 tons per year) for ROG, TOG, CO, NOx, PM10, PM2.5, and SOx for all air districts evaluated except for SJVAPCD. ARB reports these emission impacts as negligible since the analysis contains too much uncertainty in the analysis to accurately quantify such small increases. For SJVAPCD, ARB staff estimates net reductions of 0.5 tons per year of NOx and 30.1 tons per year of CO, and negligible reductions in SOx. Conversely, ARB has identified emission increases of 0.9 tons per year of PM10 and 0.3 tons per year of PM 2.5 in the SJVAPCD. The design of the proposed regulation ensures that emission impacts are well below any applicable CEQA significance thresholds for direct and cumulative impacts. The regulation decreases NOx emissions below existing levels in the San Joaquin Valley and provides substantial emission benefits of VOCs as well as smaller benefits of the BTEX suite of chemicals.

As previously stated, ARB's analysis shows a net NOx decrease of 0.5 tons per year and net increases of PM10 and PM2.5 of 0.9 and 0.3 tons per year, respectively, in the SJVAPCD. ARB's analysis uses the current baseline (i.e., emissions from current vapor control devices). The SJVAPCD has published a study of the potential to reduce NOx from existing flaring, as required by a commitment in the 2015 State Implementation Plan (SIP) for the 1997 PM2.5 Standard. In an update to the SJVAPCD Governing Board (SJVAPCD 2016), district staff state that the low-NOx vapor control devices, as required under the Proposed Regulation, will be required under the district's upcoming SIP therefore ARB must not "take credit" for NOx reductions from these devices.

Pursuant to CEQA, the baseline to be used in an environmental analysis is the physical environmental conditions as they exist at the time environmental review is commenced. ARB staff disagree that undeveloped future rules are properly considered part of the CEQA baseline. However, in an effort to fully address SJVAPCD's concerns, ARB has conducted a further analysis against a hypothetical future baseline where all existing vapor control devices are already low-NOx vapor control devices. In such a scenario, there would be no NOx benefit attributed to the Proposed Regulation for replacing current vapor control devices with low-NOx vapor control devices. Under that scenario, the Proposed Regulation would result in a NOx emissions increase in the SJVAPCD of 4.1 tons per year, CO emissions increases of 1.6 tons per year, and a negligible SOx emissions increase. PM10 and PM2.5 emissions would not change. All estimated emissions increases under this alternative scenario are below the CEQA significance threshold for the SJVAPCD of 10 tons per year for NOx, 5 tons per year for PM10, and 15 tons per year for PM 2.5. The SJVAPCD does not define CEQA significance thresholds for CO and SOx.

However, as noted above, the proper CEQA baseline for this project is existing environmental conditions, as analyzed above.

The change in NOx emissions that might occur as a result of the proposed regulation was estimated separately by staff of the SJVAPCD. The SJVAPCD analysis was limited to emissions from tanks only. For context, when comparing against this hypothetical future baseline, ARB staff estimates an additional 2.9 tpy NOx from the tank measure only. SJVAPCD staff estimates an additional 20.2 tpy NOx, an order of magnitude greater than the ARB staff estimates.

ARB staff believes these high estimates are not accurate for several reasons. SJVAPCD made assumptions on tank coverage, assumed all gas at a lease would go into one large system, assumed all recovered gas would go to a flare, and included supplemental fuel (which is not allowed in the current version of the regulation). ARB used the robust data contained within the oil and gas survey results to determine the amount of gas going to each tank system (not each facility), the number of systems above our standard, which systems were already controlled, the disposal method for each system, and did not assume supplemental fuel use since low NOx incinerators can handle waste gas. More detailed information can be found in the Draft EA.

Although the regulation decreases NOx compared to current levels, ARB staff recognizes some of the ARB's proposed NOx reduction approaches in this rule may be required in the future by the district and ARB is committed to spurring innovation in, and application of, NOx control strategies. Staff suggests following the development of the related SJVAPCD rules and exploring options to address any remaining concerns through, among other options, consideration of innovative NOx technologies or funding or implementation of NOx reduction projects.

Additionally, implementation of the proposed regulation would consist of modifications to existing facilities such as installation of vapor collection systems, and replacement or repair of leaking equipment resulting in the installation or replacement of gathering lines and piping, flanges, valves, low NO_x combustion devices pneumatic devices and pumps, and other components. Any proposed modifications to facilities would require having local or State land use approvals secured prior to their implementation. Part of the development review and approval process for projects located in California requires environmental review consistent with California environmental laws (e.g., CEQA) and other applicable local requirements (e.g., local air quality district rules and regulations). The environmental review process would include an assessment of whether or not implementation of such projects could result in air quality impacts. As described in ARB's Draft EA in Appendix C, ARB expects any construction-related impacts to air quality to be less-than-significant due to the limited nature of the modifications and upgrades to oil and gas facilities that could be required under the Proposed Regulation, consisting of activities such as installation of piping, gathering lines, tanks, valves, and hatches.

VIII. ENVIRONMENTAL ANALYSIS

The Air Resources Board (ARB), as the lead agency for the proposed regulation, has prepared an environmental analysis under its certified regulatory program (17 CCR 60000 – 60008) to comply with the requirements of the California Environmental Quality Act (CEQA). ARB's regulatory program, which involves the adoption, approval, amendment, or repeal of standards, rules, regulations, or plans for the protection and enhancement of the State's ambient air quality has been certified by the California Secretary for Natural Resources under Public Resources Code section 21080.5 of CEQA (14 CCR 15251(d)). ARB, as a lead agency, prepares a substitute environmental document (referred to as an "Environmental Analysis" or "EA") as part of the Staff Report to comply with CEQA (17 CCR 60005).

The Draft Environmental Analysis (Draft EA) for the proposed regulation is included in Appendix C to this Staff Report. The Draft EA provides an environmental analysis, which focuses on reasonably foreseeable potentially significant adverse and beneficial impacts on the physical environment resulting from reasonably foreseeable compliance responses taken in response to implementation of the proposed actions within the proposed regulation. The Draft EA is intended to disclose potential adverse impacts and identify potential mitigation specific to the proposed regulation.

Implementation of the proposed regulation would require regulated entities to take actions to limit vented and fugitive methane emissions from equipment and operations. The Draft EA states that implementation of the proposed regulations would result in beneficial impacts to GHGs through reductions in methane emissions from oil and gas operations in California. The Draft EA states that the proposed regulation would result in less-than-significant long term impacts to air quality but with reductions in VOCs. The Draft EA also states the proposed regulations could result in less-than-significant or no impacts to aesthetics, agriculture resources, air quality, biological resources (long term), energy demand, greenhouse gases (short term), geology and soils (long term), hazards and hazardous materials, hydrology and water quality (long term), land use planning, transportation and traffic, mineral resources, noise, population and housing, public services, recreation, and utilities and service systems; and potentially significant and unavoidable adverse impacts due to short term construction related impacts to biological resources (short term), cultural resources (short term), geology and soils (short term), and hydrology and water quality (short term) that are reasonably foreseeable as a result of the proposed regulation.

Written comments on the Draft EA will be accepted starting June 3, 2016 through 5 p.m. on July 18, 2016. The Board will consider the Final EA and responses to comments received on the Draft EA before considering adoption of the proposed regulation.

Table 13: Summary of Potential Environmental Impacts

Resource Area Impact	Significance Finding
Aesthetics	
Short-Term Construction-Related Impacts	Less-than-significant
Long-Term Operational Impacts	Less-than-significant
Agriculture Resources	
Short-Term Construction-Related Impacts	Less-than-significant
Long-Term Operational Impacts	Less-than-significant
Air Quality	
Short-Term Construction-Related Impacts	Less-than-significant
Long-Term Operational Impacts	Less-than-significant
Biological Resources	
Short-Term Construction-Related Impacts	Potentially significant
Long-Term Operational Impacts	Less-than-significant
Cultural Resources	
Short-Term Construction-Related Impacts	Potentially significant
Energy Demand	
Short-Term Construction-Related Impacts	Less-than-significant
Long-Term Operational Impacts	Less-than-significant
Geology, Soils and Minerals	
Short-Term Construction-Related Impacts	Potentially significant
Long-Term Operational Impacts	Less-than-significant
Greenhouse Gas Emissions	
Short-Term Construction-Related Impacts	Less-than-significant
Long-Term Operational Impacts	Beneficial impact
Hazards and Hazardous Materials	
Short-Term Construction-Related Impacts	Less-than-significant
Long-Term Operational Impacts	Less-than-significant
Hydrology and Water Quality	
Short-Term Construction-Related Impacts	Potentially significant
Long-Term Operational Impacts	Less-than-significant
Land Use and Planning	
Short-Term Construction-Related Impacts	Less-than-significant
Long-Term Operational Impacts	Less-than-significant
Mineral Resources	
Short-Term Construction-Related Impacts	Less-than-significant
Long-Term Operational Impacts	Less-than-significant

Resource Area Impact	Significance Finding
Noise	
Short-Term Construction-Related Impacts	Less-than-significant
Long-Term Operational Impacts	Less-than-significant
Population and Housing	
Short-Term Construction-Related Impacts	Less-than-significant
Long-Term Operational Impacts	Less-than-significant
Public Services	
Short-Term Construction-Related Impacts	Less-than-significant
Long-Term Operational Impacts	Less-than-significant
Recreation	
Short-Term Construction-Related Impacts	Less-than-significant
Long-Term Operational Impacts	Less-than-significant
Transportation and Traffic	
Short-Term Construction-Related Impacts	Less-than-significant
Long-Term Operational Impacts	Less-than-significant
Utilities and Service Systems	
Short-Term Construction-Related Impacts	Less-than-significant
Long-Term Operational Impacts	Less-than-significant

A. HEALTH IMPACTS

California experiences some of the highest concentrations of PM2.5 in the nation.[86] The majority of California's population lives in areas that exceed the national and state PM2.5 air quality standards.[87] [88] These standards are set based upon assessments of scientific studies that link exposure to PM2.5 to health effects, including hospitalization due to respiratory and cardiovascular illness, and premature death from cardiopulmonary disease.[89] [90] The U.S. EPA has determined that exposure to PM2.5 plays a "causal" role in premature death, meaning that a substantial body of scientific evidence shows a relationship between PM2.5 exposure and increased mortality, a relationship that persists when other risk factors such as smoking rates and socioeconomic factors are taken into account.[91] NO_x emissions impact human health because photochemical reactions convert some NO_x into ammonium nitrate aerosol, a

[86] U. S. EPA. 2012. Fine Particle Concentrations Based on Monitored Air Quality from 2009 – 2011
[87] ARB. 2013. Area Designations for State Ambient Air Quality Standards PM2.5.
[88] ARB. 2013. Area Designations for National Ambient Air Quality Standards PM2.5.
[89] ARB. 2010. Estimate of Premature Deaths Associated with Fine Particle Pollution (PM2.5) in California Using a U.S. Environmental Protection Agency Methodology.
[90] U. S. EPA. 2012. Regulatory Impact Analysis for the Final Revisions to the National Ambient Air Quality Standards for Particulate Matter.
[91] U. S. EPA. 2009. 2009 Final Report: Integrated Science Assessment for Particulate Matter.

component of PM2.5, and convert some NO_x to ozone, a major constituent of smog and a potent lung irritant.

There are no expected associated health impacts.

IX. ENVIRONMENTAL JUSTICE

Government Code section 65040.12(e) defines environmental justice as the fair treatment of people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies. ARB is committed to supporting the achievement of environmental justice. In 2001, the Board adopted a framework for incorporating environmental justice into the ARB's programs consistent with the directives of State law.[92] Although ARB's environmental justice policies apply to all communities in California, they recognize that environmental justice issues have been raised more often in the context of low-income and minority communities.

As a result of ARB's work with the public, the business sector, local government, and air districts, California's ambient air is the cleanest since air quality measurements have been recorded.[93] However, large numbers of Californians live in areas that continue to experience episodes of unhealthy concentrations of ozone and $PM_{2.5}$.

Communities located in close proximity to oil and gas operations are already experiencing the impacts of those operations including, but not limited to, odors, noise, and vehicle traffic. Additionally, these communities are at risk for exposure to a variety of volatile organic compounds and toxics, including the BTEX suite of chemicals, which are associated with oil and gas operations. Local air districts currently implement a variety of rules that reduce volatile organic compounds from the oil and gas industry. The purpose of the proposed regulation is to reduce methane emissions from the covered oil and gas operations and facilities covered with the reduction of additional volatile organic compounds and toxic air contaminants as a co-benefit of the proposed control strategies. The proposed regulation was designed to minimize or eliminate any potential air quality emission impacts in nonattainment areas and minimize potential emissions well below significance levels in attainment areas. Specifically, though some newly-collected vapors may be combusted, the proposed regulation requires that inefficient combustion devices already in use be replaced with cleaner devices before they can be used for compliance. The surrounding communities will benefit from the proposed regulation to the extent that the proposed control strategies provide reductions in emissions of volatile organic compounds and toxic air contaminants. There will be no adverse impact to the surrounding communities due to the oil and gas regulation.

[92] ARB. 2001. Policies and Actions for Environmental Justice.
[93] ARB. 2014. History of Air Resources Board.

X. ECONOMIC IMPACTS

A. SUMMARY OF PROPOSED COSTS AND IMPACTS

The proposed Regulation for the Reduction of Greenhouse Gas (GHG) Emissions from Crude Oil and Natural Gas Operations (proposed regulation) is intended to reduce GHG emissions from oil and gas production, processing, storage and transmission compressor stations. The economic impacts of the proposed regulation are discussed in this section, and include impacts and benefits to businesses, individuals, and government agencies. This section also includes a discussion of the estimated cost of the proposed regulation.

B. MAJOR REGULATIONS

For a major regulation proposed on or after January 1, 2014, a Standardized Regulatory Impact Assessment (SRIA) is required. A major regulation is one “that will have an economic impact on California business enterprises and individuals in an amount exceeding fifty million dollars ($50,000,000), as estimated by the agency.” (Govt. Code Section 11342.548) Further, the Health and Safety Code Section 57005(b) defines a “major regulation” as any regulation that will have an economic impact on the state’s business enterprises in an amount exceeding ten million dollars ($10,000,000), as estimated by the board, department, or office within the agency proposing to adopt the regulation in the assessment required by subdivision (a) of Section 11346.3 of the Govt. Code.

When amortized, the proposed regulation will cost $23 million with the enhanced underground storage monitoring plan and $14 million per year without that provision; however, the largest expenditures will be in 2018 when most of the capital equipment is expected to be purchased. This upfront cost is estimated to be over $40 million in direct costs, and over $50 million in overall economic impact. Due to the estimated economic impact of compliance exceeding $50 million in a 12 month period during 2018, the proposed regulation was determined to be a major regulation and required a SRIA. A SRIA was submitted to the Department of Finance (DOF) on February 20, 2015 and a revised version on April 29, 2015. On May 28, 2015, ARB received a letter from the DOF acknowledging the status of a major regulation, and commenting on the information presented in the SRIA. These comments are addressed in Appendix B to this document.

Since the submittal of the SRIA, the proposed regulation has undergone several changes. In addition to changes in the standards, there have been changes to the methodology of estimating the cost and emissions for provisions of the proposed regulation due to the availability of updated data and feedback from industry representatives and other stakeholders. Although these changes have been made after the submittal of the SRIA, staff believes the conclusions of the

SRIA continue to be accurate, since the overall annual cost, emission, reductions, and impacted industries are similar.

In addition to changes made to the standards of the proposed regulation, ARB is now using the 20 year AR4 value (72) of GWP instead of the 100 year AR4 value (25) to determine the reductions in CO_2e. Also, the value assigned to gas saved changed from $4.10 per mscf to $3.44 per mscf. This value was changed to reflect the most recently available data and is the average wholesale price that is specific to California over the last 12 months of available data, from November 2014 to October 2015.[94] Also, the compliance dates for the regulation have changed from starting January 1, 2017, to starting January 1, 2018.

In addition to the changes discussed above, some of the methodologies of estimating the potential costs and emission have changed. This is due to the availability of better data, stakeholder comments, as well as the continued development of the proposed regulation. These changes are described in detail below. All SRIA emissions use a GWP of 25, and all current emissions use a GWP of 72 in the descriptions.

1. Changes from SRIA

a) Reciprocating Compressors

In the SRIA version of the proposed regulation, all reciprocating compressors would need to replace a rod packing after three years of use. In the current version of the proposed regulation, compressors at production facilities are no longer subject to a rod packing leak standard, but instead are required to meet an LDAR standard. Many of the compressors at production facilities are smaller, may be portable, and handle a different composition of gas than compressors at processing, storage or transmission facilities. In addition, most of the available data concerning leak rates and rod packing cost and performance are from larger compressors that are typically not found at production facilities. The provision to exclude production type compressors eliminated over 600 of almost 1000 compressors from this segment, for determining cost and emissions. In addition, industry provided data on the leak rate by compressor for a large subset of the remaining compressors. This new data was used in place of the emission factors previously used. With the reduction in number of compressors, the change from a time based standard to a performance based standard, and using measurement data instead of emission factors, the estimated reduction of emissions has changed from 143,000 MT CO_2e to about 68,000 MT CO_2e. Based on the

[94] U. S. EIA. 2016. U.S. Natural Gas Citygate Price (Dollars per Thousand Cubic Feet).

decrease of compressors potentially impacted by the standard for rod packing leaks, the estimated cost of compliance has decreased from about $600,000 per year to about $260,000 per year.

b) Centrifugal Compressors

In the SRIA version of the proposed regulation, 25 centrifugal compressors with wet seals were anticipated to need a vapor recovery system or to be converted to a dry seal. In an effort to verify this data from ARB's 2009 Survey, staff contacted the facilities that would be impacted by this provision in the proposed regulation. All centrifugal compressors, except for one, were reported with wet seals in error, are no longer in use, have been replaced with a compressor with a dry seal, or now have a vapor recovery system installed to control emissions. In addition, measurement data taken directly from this single compressor was used in place of the emission factors used to generate the emissions and reductions for the SRIA. Due to the updated number of impacted units, the emissions dropped from about 20,000 MT CO_2e to about 3,700 MT CO_2e and the reduction estimates dropped from about 10,000 MT CO_2e to about 3,500 MT CO_2e. The associated cost of compliance decreased from about $375,000 per year to about $6,000 per year.

c) LDAR

In the SRIA version of the proposed regulation, the emissions did not include a small percentage of super emitter components, which are responsible for the majority of emissions. In addition, the LDAR program was changed from an annual inspection to a quarterly inspection requirement. These changes were made to address stakeholder comments, and ensure emissions were determined with the best available data. The estimated emissions reduction has changed from about 1,200 MT CO_2e to about 590,000 MT CO_2e, and the estimated cost has changed from about $2 million per year to about $10 million per year.

d) Pneumatic Devices

At the time of the SRIA, all continuous bleed pneumatic devices were required to change to a low bleed pneumatic device. Based on stakeholder feedback, this has been changed to require a no bleed pneumatic device in the current proposed regulation to maximize emission reductions with no increased cost. Also, after a review of the data, the count of continuous bleed devices was overestimated by about 170. The anticipated emissions reduction from this segment have changed from about 124,000 MT CO_2e to about 320,000 MT

CO_2e, and the estimated cost has changed from about $1.3 million per year to about $1.2 million per year.

e) Tank and Separator Systems

The provisions for tank and separator systems have changed from requiring a vapor recovery system for all uncontrolled systems, to require vapor recovery and comply with a NO_x emission standard, but only for uncontrolled systems that are anticipated to have over 10 MT per year of CH_4 emissions. Due to this change, the estimated number of systems impacted changed from over 600 to about 300. It is now assumed that a low NO_x incinerator will be used to comply with the NO_x emission standard in place of a flare. The emissions are now calculated with the throughput to the separators instead of limited, reported emissions data from the 2009 ARB survey. The estimated emissions reductions have changed from about 252,000 MT CO_2e to about 540,000 MT CO_2e. The estimated cost has changed from about $16 million per year to about $4.7 million per year.

f) Well Stimulations

The current proposal uses emission factors from WSPA[95] to estimate emissions from well stimulations. These emission factors became available after the submittal of the SRIA when the best available data projected much greater emissions. The estimated emissions reduction from this segment of the proposed regulation has changed from about 24,400 MT CO_2e to about 5,000 MT CO_2e. The estimated cost has changed from about $200,000 per year to about $460,000 per year due better cost data becoming available and inclusion of additional compliance equipment.

g) Liquids Unloading

The requirement for controls for liquids unloading were removed for the proposed regulation, and replaced with a reporting requirement. The estimated reductions of about 350 MT CO_2e have been eliminated, and the expected cost of $450,000 per year has been replaced with a cost of about $6,000 for reporting and recordkeeping.

h) Monitoring Plan

The proposed regulation now includes a monitoring plan, which requires operators of natural gas storage facilities to monitor gas wells on a daily basis, and install a system for ambient air monitoring. This was not included in the SRIA. The cost of this provision is estimated to be about $8.7 million per year.

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[95] WSPA. 2015. Recirculation Tank Emissions Testing, Source Test Report.

C. ECONOMIC IMPACTS ASSESSMENT

The proposed regulation encourages the use of more efficient and potentially cost-saving technology to ensure maximum production of natural gas. Much of the capital equipment purchased, such as vapor recovery for tanks, have lifetimes that far exceed the pay-off period. Though at some point the primary industries no longer are making payments for the capital required for compliance, they continue to enjoy the natural gas savings that are provided by that capital. Therefore, the primary industries oil and gas extraction and natural gas distribution, are required to make minor changes to their production facilities, these modifications include increases in efficiency that may result in net benefits to regulated parties in the long run. Secondary industries face increased product demand, resulting in increased output and employment in those industries.

The proposed regulation was analyzed using generally high estimates and GHG emission reduction estimates; thus, the analysis may serve as an upper bound of anticipated impacts. To the extent there are greater cost savings due to increased product capture, the economic impacts of the proposed regulation would be less negative in all years, and likely show a benefit to the economy. This result would persist in later years and the primary industries, having made a large initial investment in the capital necessary to prevent substantive leaks, would continue to see savings long after the payments for the capital are finished.

The proposed regulation is unlikely to significantly impact California's economy, including the growth of employment, investment, personal income, output, and GSP does not represent a significant change from Business as Usual (BAU).

D. COST EFFECTIVENESS

1. Cost Analysis and Costs per Ton

This section describes the sources and general methodology to determine the emissions, cost, and cost per ton of the proposed regulation. In general, for each segment of the regulation, staff identified the number of devices affected, estimated the cost to comply with the regulatory provisions, estimated emissions and reductions, and accounted for any savings to be included in the cost per ton. Cost per ton is the dollars spent to reduce a unit mass of a specified pollutant, in this case methane. The general methodology to determine these items for each segment of the regulation is described below and is described in more detail in Appendix B. Costs are based on best estimates at the time of preparation.

The indirect costs and economic impacts were modeled using a computational general equilibrium model of the California economy known as Regional Economic Models, Inc. (REMI). The REMI model generates year-by-year estimates of the total regional effects of a policy or set of policies. These results and analysis are included with the SRIA in Attachment C. The results helped evaluate the impact of the proposed regulation on California's economy, including business impacts, job creating, and impacts to individuals. Finally, alternatives to the proposed regulation were evaluated and fiscal impacts to ARB and local air districts were estimated. The cost estimate of the proposed regulation follows guidelines recommended by the California Environmental Protection Agency (Cal/EPA), and is consistent with the methodologies used in previous cost analyses for ARB regulations (ARB, 1999; ARB, 2000; ARB, 2004; ARB, 2005; ARB, 2007). The segments analyzed for this proposed regulation include control strategies for reciprocating compressors, centrifugal compressors, oil and water separators and storage tanks, pneumatic devices, circulation tanks for well stimulations, and a leak detection and repair (LDAR) program. Information from this survey, of which parts were later updated by staff to account for changes since 2009, was used to form the basis of the number and types of facilities potentially impacted, number and types of equipment, and estimated emissions reduction from the standards in the proposed regulation. After the number and types of equipment impacted were identified, the direct cost to industry was estimated for each component of the regulation. Sources of data include ARB's 2009 Survey, ICF's Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF Report), EPA documents including their Gas Star Program, industry groups, and communications with operators of potential control equipment, and other stakeholders. Appendix B details the methodology and calculations by sector.

Table 14: Summary of Cost, Emissions, and Cost per Ton using the 20 year and 100 year GWP respectively

Provision	Annual Cost	Annual Savings	Reductions using 20 year GWP (MT CO_2e)	Cost per Ton using 20 year GWP ($ / MT CO_2e reduced)	Cost per Ton using 20 year GWP with Savings ($ / MT CO_2e reduced)	Cost per Ton Using 100 year GWP ($ / MT CO_2e reduced)	Cost per Ton with Savings Using 100 year GWP ($ / MT CO_2e reduced)
VRU for Tanks	$4,700,000	$500,000	540,000	$ 9	$ 8	$25	$23
Reciprocating Compressors	$260,000	$180,000	68,000	$ 4	$ 1	$11	$3
LDAR	$10,000,000	$1,500,000	590,000	$ 17	$ 14	$49	$41
Pneumatic Devices	$1,200,000	$840,000	320,000	$ 4	$ 1	$10	$3
Well Stimulations	$460,000	$0	5,000	$ 91	$ 91	$262	$262
Centrifugal Compressors	$6,000	$9,000	3,500	$ 2	$ (1)	$5	$(2)
Monitoring Plan	$8,700,000	$0	0	NA	NA	NA	NA

Total	**$25,400,000**	**$3,000,000**	**1,500,000**	**$17**	**$15**	**$48**	**$42**

All Figures are in 2015 dollars

2. Direct Costs

a) Direct Costs on Individuals

For 2017, the baseline projected outputs for oil and gas extraction and natural gas distribution industries are approximately $25 billion and $19 billion respectively. The ratio of compliance cost to total output is less than 0.5 percent for both industries, making it likely that pass-through of costs would be unnoticeable. However, to the extent that any potential costs are passed on to individual consumers, minor increases in the price of natural gas and electricity may occur.

b) Direct Costs on Typical Businesses

Any business involved with crude oil or natural gas extraction, natural gas storage, crude oil processing excluding refineries, natural gas processing (including gas plants), crude oil tank farms (excluding tank farms at refineries), or transmission of natural gas will potentially be impacted by the proposed regulation. In February 2009, ARB conducted an Oil and Gas Industry Survey for crude oil and natural gas production, processing, and storage facilities in California.[96] The survey was completed by 325 companies representing over 1,600 facilities and approximately 97 percent of the 2007 crude oil and natural gas production in California. Out of these companies, 272 companies that responded to the survey are expected to be impacted by the provisions in the proposed regulation.

ARB estimates the direct cost to industry for the proposed regulation to be approximately $25 million per year. This includes the amortized cost of capital equipment, and annual costs for labor, maintenance, reporting and recordkeeping. ARB generally used high estimates throughout for estimating emissions, costs, and reductions. The average impact each of the 272 businesses is expected to be about $100,000 per year. The typical businesses are not small because the primary industries are ineligible to be classified as small under government code.[97] Therefore, the increased costs on industry do not directly impact small businesses.

The proposed regulation will impact some businesses that would have otherwise been classified as a small business. Small businesses with estimated annual revenue of less than $10 million per year, but greater

[96] ARB. 2013. ARB 2007 Oil and Gas Industry Survey Results, Final Report, revised in October 2013.
[97] Government Code Section 11342.610(b). 2016. Small Business Procurement and Contract Act. http://www.leginfo.ca.gov/cgi-bin/displaycode?section=gov&group=14001-15000&file=14835-14843.

than $2.5 million per year, as estimated by annual gas and oil production from ARB's survey (ARB, 2013) are expected to incur costs of about $16,000 per year to comply with the provisions in the proposed regulation. These businesses have average revenue of about $5.2 million, and the estimated costs account for less than 0.5% of the estimated annual revenue. Microbusinesses are businesses with annual revenue of less than $2.5 million per year. Based on ARB's survey (ARB, 2013), these businesses have an average revenue of about $780,000 and will incur costs of about $3,700 annually. This accounts for less than 0.5% of the estimated annual revenue.

3. Cost Analysis

a) Benefits

The proposed regulation is anticipated to deliver environmental benefits that include an estimated annual reduction in GHG emissions, beginning in 2018, of about 1.5 million MT CO_2e per year from oil and gas related operations in California. In addition, the proposed regulation is expected to save primary industries about 800 million standard cubic foot (scf) per year of industrial natural gas through reductions of leaks and vapor recovery systems[98]. This will result in a savings of about $3 million per year, assuming the value of this gas is $3.44 per Mscf. The cost per ton of the proposed regulation is estimated to be approximately $15 per MT CO_2e reduced. These estimates use the 20-year GWP for methane (i.e., 72) from the Intergovernmental Panel on Climate Change's (IPCC) Fourth Assessment Report (AR4).

Using the 20-year GWP shows the impact of reducing methane in the short term when compared to carbon dioxide. Reducing SLCPs, such as methane, can produce near term results that deliver immediate and tangible climate, air quality, economic, and health benefits while longer-term changes are being implemented.

The proposed regulation is also expected to provide co-benefits of reductions in emissions of VOCs and toxic air contaminants that are emitted from uncontrolled oil and water storage tanks and released from well stimulation circulation tanks. The estimated reduction in VOCs is approximately 3,630 tons per year, or about 10 tons per day statewide. There was the potential for NO_x increases for vapor recovery units if the facility used a flare. However, since the proposed regulation would impose a NO_x standard in these cases where none or a less stringent one applied before, the overall impact is a small but

[98] This assumes gas is 94.9% CH_4.

beneficial with a reduction of about 1.6 metric tons per year, but there are NOx impacts from LDAR leading to an overall impact that is neutral for the state as a whole. Table 12, above, summarizes reductions of all pollutants, and detailed calculations are in Appendix D.

b) Benefits to Individuals

The proposed regulation will not directly affect individual consumers; however, as a result of the anticipated decrease in methane emissions, VOCs, and other toxic air contaminants, the proposed regulation will provide health and climate benefits.

Like emissions of other GHGs, emissions of methane due to human activities (anthropogenic emissions) have increased markedly since pre-industrial times. Of the GHGs emitted as a result of human activities, methane is the second most important GHG after carbon dioxide (CO_2), accounting for 14 percent of global GHG emissions in 2005. Though methane is emitted into the atmosphere in smaller quantities than CO_2, its global warming potential (i.e., the ability of the gas to trap heat in the atmosphere) is 72 times that of CO_2, resulting in methane's stronger influence on warming during its atmospheric life time.[99]

California experiences some of the highest concentrations of PM2.5 in the nation.[100] The majority of California's population lives in areas that exceed the national and state PM2.5 air quality standards.[101] [102] These standards are set based upon assessments of scientific studies that link exposure to PM2.5 to health effects, including hospitalization due to respiratory and cardiovascular illness, and premature death from cardiopulmonary disease.[103] [104] The U.S. EPA has determined that exposure to PM2.5 plays a "causal" role in premature death, meaning that a substantial body of scientific evidence shows a relationship between PM2.5 exposure and increased mortality, a relationship that persists when other risk factors such as smoking rates and socioeconomic factors are taken into account.[105] NO_x emissions impact human health because photochemical reactions convert some NO_x into ammonium nitrate aerosol, a component of PM2.5, and

[99] GMI. 2016. About Methane. https://www.globalmethane.org/about/methane.aspx
[100] U. S. EPA. 2012. Fine Particle Concentrations Based on Monitored Air Quality from 2009 – 2011
[101] ARB. 2013. Area Designations for State Air Quality Standards.
[102] ARB. 2013. Area Designations for National Air Quality Standards.
[103] ARB. 2010 Estimate of Premature Deaths Associated with Fine Particle Pollution (PM2.5) in California Using a U.S. Environmental Protection Agency Methodology.
[104] U. S. EPA. 2012. Regulatory Impact Analysis for the Final Revisions to the National Ambient Air Quality Standards for Particulate Matter.
[105] U. S. EPA. 2009. 2009 Final Report: Integrated Science Assessment for Particulate Matter. DC, EPA/600/R-08/139F, 2009.

convert some NO_x to ozone, a major constituent of smog and a potent lung irritant.

The PM2.5 and NO_x emission changes due to the proposed regulation are expected to be negligible, and so there are no expected associated health impacts.

c) Benefits to California Businesses

The proposed regulation requires the oil and gas industry to purchase, retrofit, and service capital equipment. The requirements of the regulation would increase the demand for these services and increase business opportunities for secondary industries both within and outside of California. Additionally, the proposed regulation is designed to reduce industrial natural gas leakage, which will result in cost savings for the regulated parties. For example, many of the proposed control strategies are designed such that natural gas can be recovered and either used on site as energy or captured for sale. These savings are estimated to be about $ 3 million per year. While the primary industries are not small businesses, by definition, some of the secondary industries contain small businesses. If these businesses were able to meet the increased demand and provide the capital equipment and services to the primary industries for compliance, small businesses would see increased demand, output and, likely, employment.

ARB estimates that more than $25 million each year will be spent on control equipment and inspection services. This includes over $10 million complying with the LDAR provisions in the proposed regulation. Companies involved in LDAR inspections may see an increase in business or expansion. In areas of the state that previously did not have an inspection program, there will be new demand for a previously unneeded service, which may result in new businesses being created.

In areas without existing VOC based regulations for LDAR or higher pressure natural gas systems, LDAR is likely to be more cost effective. Also, staff believes that with the advent of newer technologies, the efficiency of LDAR inspections will improve.

While direct costs to the primary industries exceed $40 million in the first year of implementation, these industries achieve savings of about $3 million annually from leakage prevention strategies within the proposed regulation. Secondary industries also achieve benefits, as demand for their equipment, services, or other products such as natural gas increases yielding positive economic benefits.

E. IMPACTS TO CALIFORNIA, STATE, OR LOCAL AGENCIES

1. Fiscal Impacts

a) ARB and Air Districts

The proposed regulation's enforcement and implementation provisions recognize that California's local air districts already play an important role in regulating the oil and gas sector, and are intended to build on their efforts. The provisions make clear that ARB can directly enforce the proposed regulation, but also offer paths for local air districts to integrate its requirements into their existing programs to support efficient and effective enforcement.

ARB's proposed regulation can be implemented and enforced by both ARB and the districts. ARB staff assumes most local air districts will choose to take the lead in implementing and enforcing the regulation, with ARB playing a backstop role, and it is our preference for the local air districts to do so. However, ARB will take a lead role in districts that choose not to. The local air districts are more familiar with operators, conduct inspections nearby or at the same sites, and in many instances have been regulating such sources for decades. This is why the regulation allows local districts to enter into MOUs with ARB in order to define implementation and enforcement responsibilities, as well as for information sharing. The regulation also allows for districts to incorporate this regulation into their local rules. To ensure uniform enforcement, however, districts may not waive or reduce the stringency of the state rules, which remain state law, enforceable as necessary by ARB.

A local air district may decide – but is not obligated -- to be the primary agency responsible for enforcing the provisions of the proposed regulation. This includes issuing permits for new control equipment, registration and inspection of equipment, and enforcing the LDAR portion of the regulation. The individual district cost estimates range from amounts some districts feel could be absorbed by them without additional funding, to over $300,000 per year in recurring costs and almost $1,000,000 in one-time costs, primarily for permitting. Even if the districts do decide to implement and enforce this regulation, there is an annual cost for ARB to manage the reporting requirements in the regulation. The costs to districts are estimated to be approximately $1,300,000 in initial costs, and approximately $660,000 in ongoing costs.

Although local agencies (air districts) may choose to implement this regulation, and certain aspects of it may be incorporated in permits as a matter of preexisting law, resulting in some fiscal impacts, the regulation imposes no reimbursable mandates. Air districts face no new legal requirements specific to them under this regulation. As to implementation tasks they may take on or any other costs that may result by operation of statute, air districts have legal authority under Health and Safety Code sections 40510 and 42311 to recover related costs by imposing fees. The Proposed Regulation also specifies that local air districts that choose to enforce the regulation may retain any penalty monies that result. ARB also may make arrangements to further support air districts as a voluntary matter. Thus, because the regulation applies generally to all entities operating affected sources, not the air districts, and so does not impose unique new requirements on local agencies, this is not a reimbursable mandate. (*County of Los Angeles v. State of California*, 42 Cal. 3d 46 (1987).

The proposed regulation's enforcement and implementation provisions recognize that California's local air districts already play an important role in regulating the oil and gas sector, and are intended to build on their efforts. The provisions make clear that ARB can directly enforce the proposed regulation, but also offer paths for local air districts to integrate its requirements into their existing programs to support efficient and effective enforcement. ARB's proposed regulation can be implemented and enforced by both ARB and the districts. ARB staff assumes most local air districts will choose to take the lead in implementing and enforcing the regulation, with ARB playing a backstop role, and it is our preference for the local air districts to do so. However, ARB will take a lead role in districts that choose not to. The local air districts are more familiar with operators, conduct inspections nearby or at the same sites, and in many instances have been regulating such sources for decades. This is why the regulation allows local districts to enter into MOUs with ARB in order to define implementation and enforcement responsibilities, as well as for information sharing. The regulation also allows for districts to incorporate this regulation into their local rules. To ensure uniform enforcement, however, districts may not waive or reduce the stringency of the state rules, which remain state law, enforceable as necessary by ARB.

ARB staff estimates that the regulation will require 6 PYs to implement depending on the mix of district and ARB implementation. In addition to PYs, ARB will need to purchase equipment including three IR cameras at $85,000 each, and three toxic vapor analyzers at $10,000 each. The costs are higher with ARB enforcement than with district enforcement due to the need to travel, train new staff, and set-up programs including a registration program. The total cost to ARB is estimated to be $285,000 in initial costs ((3 X $85,000) + (3 X $10,000)), and about $870,000 in ongoing costs (6 X

$145,000). These costs are anticipated to be imposed during the 2017/2018 fiscal year.

b) Other State Agencies

The proposed regulation does not affect other state agencies.

XI. REFERENCES, TECHNICAL, THEORETICAL, AND/OR EMPIRICAL STUDY, REPORTS, OR DOCUMENTS RELIED UPON

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